BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-02-1

IDAHO POWER COMPANY

EXHIBIT NO. 106

DENNIS E. PESEAU

DRAFT FUEL PRICE FORECASTS FOR THE 5TH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

April 25, 2002

Council Document 2002-07

Table of Contents

Draft Fuel Price Forecasts For the Fifth Power Plan

April 25, 2002

Introduction

Fuel prices enter into electricity planning in two primary ways. They influence electricity demand because they are substitute sources of energy for space and water heating and some other end-uses as well. They influence supply because they are potential fuels for electricity generation. Natural gas, in particular, has become the most cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines.

Traditionally, the Council has developed very detailed forecasts of electricity demand using models that are driven by economic, fuel price, and technological assumptions. For a number of reasons, the Council has chosen to retain many elements of its long-term demand forecasts from the 4th power plan, making modifications as needed to reflect significant changes that might affect the long-term trend of electricity use. Therefore the fuel price assumptions will not directly drive the demand forecasts of this power plan. But to the extent they are significantly different from the assumptions underlying the 4th power plan, we will examine the effects we might expect on demand forecasts.

The fuel price forecasts will continue to affect the expected absolute and relative cost of alternative sources of electricity generation. Through their effects on generation costs, they will also largely determine the future expected prices of electricity, which could also indicate a need to adjust the electricity demand forecast if it is significantly changed from the 4th power plan electricity price forecast.

This paper describes draft fuel price assumptions for the Northwest Power Planning Council's 5th power plan. Three major sources of fossil fuels are addressed; natural gas, oil, and coal. For each, the paper provides some background on historical consumption patterns and prices. This is followed by a description of the methods used to forecast fuel prices and the resulting forecasts. Appendices provide more detail on the methods and forecasts.

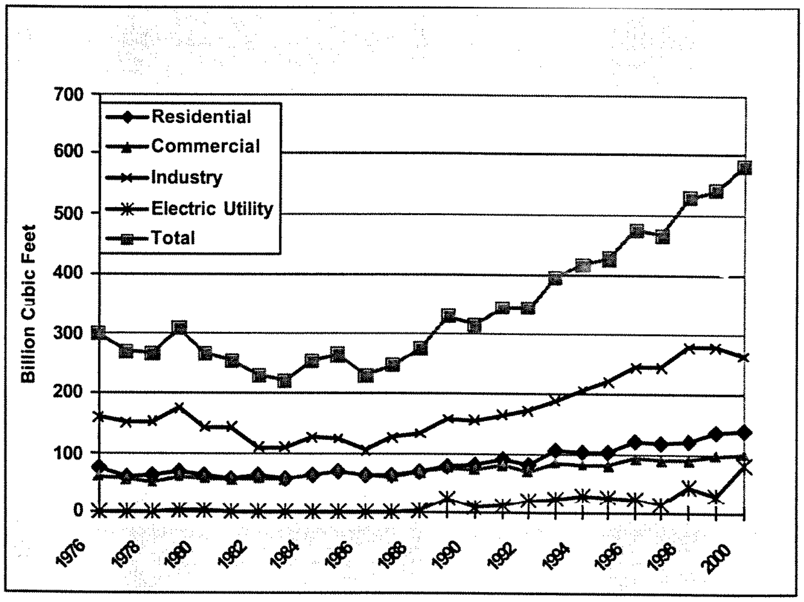
Natural Gas

Historical Consumption and Price

In 2000, the Pacific Northwest consumed 581 bcf (billion cubic feet) of natural gas. About 45 percent of this natural gas was used in the industrial sector, which includes electricity generation by non-utility power plants. About a quarter of the natural gas use is in the residential sector and about 17 percent is in the commercial sector. In 2000 electric utilities consumed 83 billion cubic feet of natural gas, or about 14 percent of the regional total natural gas consumption. Utility natural gas consumption in 2000 was nearly 3 times the amount consumed in 1999, and it remained high in 2001. Clearly, the natural gas use for electricity generation was extraordinary in 2000 and 2001 due to the electricity crisis in the West. Generating plants normally used only during extreme peak electricity needs were operated for much of the winter of 2000-01. However, new gas-fired generation has also been built during this time, which will increase normal levels of gas use for electricity generation. Natural gas use for electricity generation receives further discussed later.

The regional consumption of natural gas has grown rapidly over the last several years. Between 1986 and 2000 regional natural gas consumption grew 6.8 percent a year, more than doubling natural gas consumption over a 14-year period. Figure 1 shows natural gas use by sector since 1976. After 1986, all sectors grew, but the industrial sector accounted for nearly half of the increase in gas consumption and grew at a higher rate than residential and commercial use.

Figure 1
Pacific Northwest Natural Gas Consumption



Source: Energy Information Administration and NPPC calculations.

The rapid growth in natural gas use since 1986 has coincided with a period of ample natural gas supplies and attractive prices coupled with strong economic growth in the region. Figures 2a and 2b illustrate the Pacific Northwest natural gas prices and consumption since 1976 for the residential and industrial sectors. High natural gas prices and a severe economic downturn in the early to mid-1980s kept natural gas consumption low. However, following the deregulation of natural gas prices in the late 1980s, prices fell and demand began to grow rapidly. Natural gas displaced oil and other industrial fuels for economic and environmental reasons during this time. Higher electricity and oil prices for residential consumers combined with lower natural gas prices, made natural gas a more attractive heating fuel for homes.

Figure 2a
Pacific Northwest Industrial Natural Gas Consumption and Price

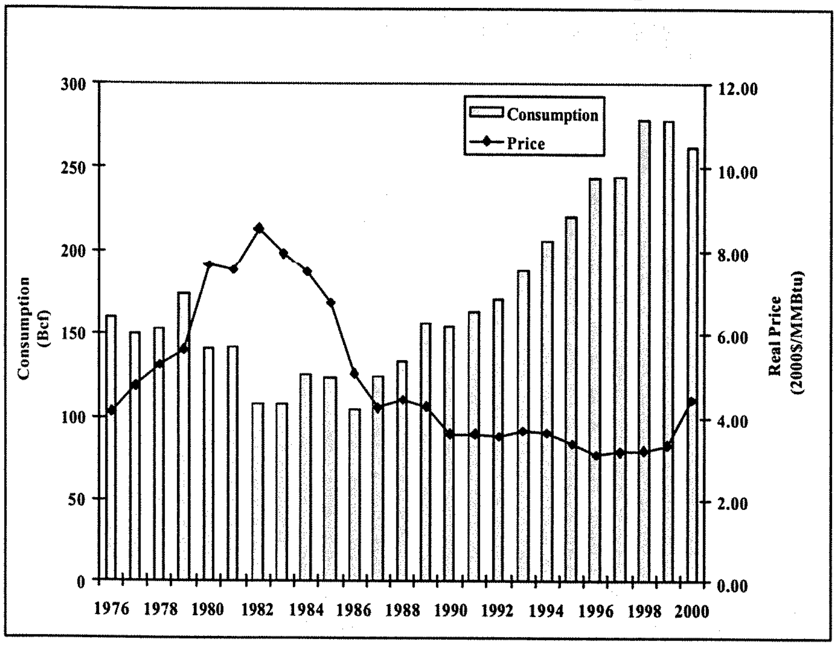
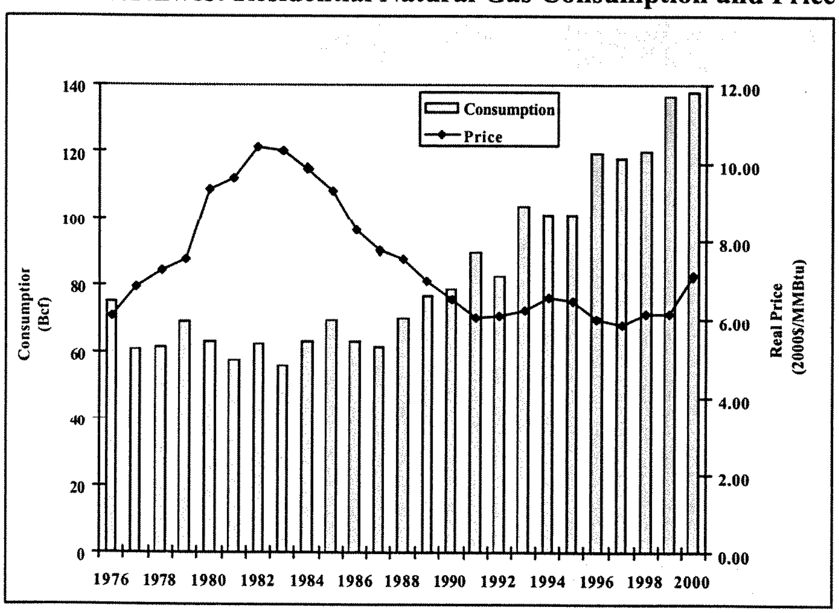


Figure 2b
Pacific Northwest Residential Natural Gas Consumption and Price



The most significant trend in natural gas markets recently has been the increasing use of natural gas for electricity generation. This is a relatively recent trend, but attracts a lot of attention because of the expectations of rapid growth in the future. Figure 1 showed that there has been some gas used for electricity generation by electric utilities since 1988. It increased recently, but is still a relatively small amount of the total natural gas use in the region. Non-utility electricity generators have used additional natural gas, but the data does not allow it to be broken out from overall industrial sector natural gas use. Given the level of concern about natural gas supplies, and the potential for a greatly increased use for electricity generation, it is worth understanding the current and potential role of natural gas in electricity generation.

Natural gas currently accounts for only 9 percent of the region's electricity generation capacity. In terms of average energy generated the share is higher at 14 percent. That is because the hydroelectric capacity, which dominates the region's generating capacity, is limited in its annual production by the amount of water available so that its share of average generation is much lower than its capacity rating. At the end of 2000 there were 32 plants that could generate electricity using natural gas with a combined generating capacity of 3,328 megawatts. In 2001 an additional 1,187 megawatts of gas-fired generation was put in service in the region, a 36 percent increase in gas-fired generation capacity. Over half of the pre-2001 capacity (1,786 megawatts) had been built since 1990. Seventy five percent of this capacity is owned by electric utilities. Many of the plants have the ability to burn other fuels such as, wood waste, refinery gas, or oil.

If all of these plants were operating, they have the capability to burn 662 million cubic feet of natural gas per day. For perspective, this can be compared to the total capacity to deliver natural gas to the I-5 corridor on a peak day in 2001, which was estimated to be 3,589 million cubic feet.[1] If operated continuously for a year they could burn 242 billion cubic feet of natural gas. This compares to an estimated 2001 total regional natural gas consumption of 670 billion cubic feet.

However, gas-fired generating plants in the region have not operated for a large part of the year, nor have they typically operated during peak natural gas demand events. This is partly due to the fact that in most years there is surplus hydroelectricity in the region. For example, utility-owned natural gas-fired generating plants in place at the end of 2000 had the capability to burn 185 billion cubic feet a year if operated continuously on natural gas. However, as shown in Figure 1, utilities only consumed 83 billion cubic feet of natural gas in 2000, and that was far more than was consumed in any previous year. If the non-utility electricity generating capacity were assumed to operate at the same capacity factor, they would have consumed only 25 billion cubic feet out of the 262 billion cubic feet of total industrial consumption in 2000.

Most natural gas-fired electricity generation in the region has not operated on firm natural gas supplies and delivery in the past. By buying interruptible service, the cost of natural gas can be reduced substantially. When interruptions come, during peak natural gas demand times, most of the plants can switch to alternate fuels. Increasingly, new gas-fired generation plants are intended to operate at a high capacity factor and are more likely to use firm natural gas supplies and transportation.

The use of interruptible demand is a key feature in the ability of the natural gas industry to meet peak day demands for its product. Figure 3 illustrates the role of interruptible consumers in meeting peak day natural gas demand.[2] The use of natural gas storage withdrawal and the injection of

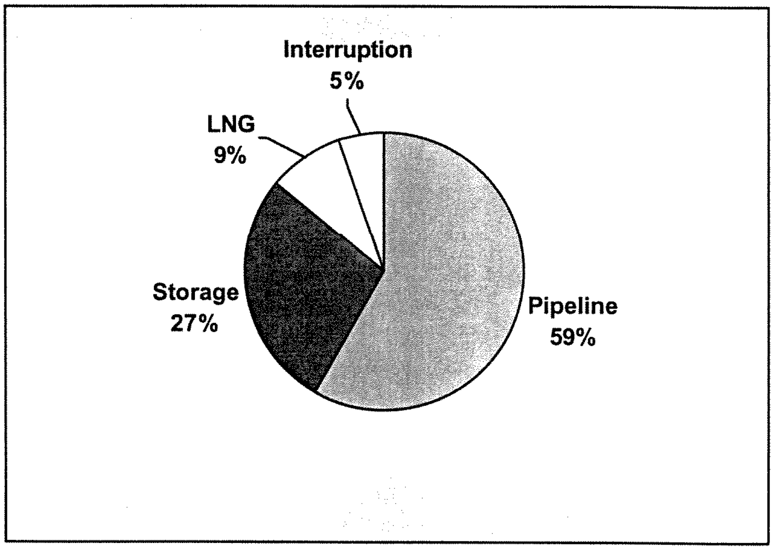
[1] Regional Resource Planning Study, BC Gas Utility Ltd., July 10, 2001.

[2] Based on Regional Resource Planning Study, BC Gas Utility Ltd., July 10, 2001.

liquefied natural gas or propane-air mixtures into pipelines are also used to increase the capacity utilization of natural gas pipelines.

With a growing share of natural gas demand expected to be firm electricity generation, the share of interruptible demand may fall as a percent of total demand. This is likely to increase the value of other strategies for meeting peak gas demand such as storage and propane/air injection. To the extent that increased gas-fired electricity generation turns out to add substantially to highly variable natural gas demand, the overall capacity factor of natural gas consumption would decrease. Lower capacity factors mean that, in general, the cost of natural gas of a per unit consumed basis could increase as fixed capacity costs are spread over a smaller amount of consumption per unit of capacity. This is not the only possibility, however. If many new gas-fired generating plants operate at a high capacity factor, or if they tend to operate more in the summer, they could have the opposite effect. They could partly offset the highly seasonal demand of the residential and commercial sectors and raise the overall capacity factor of the natural gas system.

Figure 3
Contributions to Peak Day Natural Gas Supplies



In the summer of 2000, the use of natural gas-fired generation changed substantially on the West Coast. Poor hydroelectricity supplies and a growing electricity generating capacity shortage caused electricity prices to increase by a factor of 10 or more. The extremely high electricity prices made it attractive to burn gas for electricity generation; it was very profitable, and the electricity was badly needed to meet electricity demand. As a result, the use of natural gas on the West Coast for electricity generation increased dramatically. For example, it has been reported that California generators consumed 690 billion cubic feet of gas in 2000 compared to a normal consumption of 270 billion cubic feet.[3] Much of this increase in natural gas use began in the summer when natural gas use is typically lower and natural gas is injected into storage for use during the next winter heating season.

[3] Natural Gas Week, Vol. 17, No. 18 (April 30,2001).

The problem created in natural gas markets may be some indication of the effects of the predicted growing natural gas use for electricity generation in the future. In many regions, electricity use peaks in the summer. Growing use of natural gas for electricity generation has the potential to change the traditional seasonal patterns of natural gas storage and withdrawals. Less than expected storage injections last summer and fall led to concerns about natural gas shortages for the winter and pushed prices for natural gas to levels not seen since the early 1980s. This problem was especially severe in California, and combined with pipeline capacity strains, pushed prices in the West to levels several times historical levels.

However, the dramatic increase in the use of natural gas in existing generation plants in 2000 and 2001 clearly had an exaggerated effect on natural gas markets and prices. Due to the sudden and severe shortage in electricity supplies and the unprecedented electricity prices, the natural gas delivery system in the West was pushed far beyond normal operational patterns. Thus, the impacts on natural gas prices were more severe than should be expected from an orderly development of additional natural gas demands for electricity generation.

Nearly all new proposed electricity generation capacity is natural gas fired. Although natural gas consumption only recently returned to the levels of the early 1970s, substantial growth is now being projected due to growing plans for electricity generation. The U.S. Energy Information Administration is forecasting a growth in natural gas use of 2.0 percent per year for the next 20 years.[4] Residential, commercial and industrial sector natural gas use is projected to grow modestly at a little over 1 percent per year, but natural gas use for electricity generation is projected to grow by over 5 percent a year. The EIA forecasts would result in total U.S. natural gas consumption increasing from the current level of about 23 trillion cubic feet per year to nearly 34 trillion cubic feet in 2020.

In the Pacific Northwest, complete reliance on natural gas fired generation to meet a projected electricity demand growth of 1.5 percent a year for the next 20 years could add 432 billion cubic feet of natural gas consumption to the current 540 billion cubic feet per year. This is nearly a doubling of natural gas consumption over 20 years. Modest growth in other sectors' natural gas use could easily complete the doubling of natural gas use in the region over the next 20 years. This is not unprecedented since Northwest consumption of natural gas more than doubled in the 13 years between 1986 and 2000. However, it will require continued expansion of natural gas supplies, pipeline capacity, and other elements of the natural gas delivery system, such as storage.

To the extent that the western United States depends on natural gas for new electricity generation, the price of natural gas will be a key determinant of future electricity prices. Economic theory suggests that over the long run electricity prices will be equal to the cost of new sources of supply.

Natural Gas Resources

Currently, U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. In 2000, the United States imported 3.6 trillion cubic feet of natural gas from Canada; 0.5 trillion cubic feet were imported to the Pacific Northwest.

Natural gas is created by natural processes and is widespread. Most current recovery methods attempt to exploit natural geologic formations that are able to trap natural gas in concentrated

[4] U.S. Energy Information Administration, Annual Energy Outlook 2002.

pockets. However, natural gas occurs in more dispersed forms as well. Eventually, it is likely to become possible to recover natural gas from some of these formations. Coal bed methane is a good example. Substantial amounts of natural gas are often associated with coal deposits. In the last several years methods have developed, with some government incentives, to extract the natural gas from coal formations and this coal bed methane has made substantial contributions to the natural gas supplies in the Rocky Mountain area. It now accounts for about 7.5 percent of U.S. natural gas production.[5] Expansion of natural gas supplies eventually will have to move into these less conventional areas in terms of both geographic structures and locations. As natural gas supplies expand into unconventional sources and less accessible areas costs are expected to increase. How much they increase depends a great deal on technological developments in the exploration and recovery field.

The availability of natural gas to meet growing demands is a key issue. Assessing natural gas resources is a confusing and difficult exercise. There is no absolute answer to the question of how much natural gas there is and how long it will last. Traditionally, the question has been approached on a North American basis although Mexico has not traditionally played a large role. With the potential for increased use of liquefied natural gas (LNG) imports and exports, the market could become international, similar to current oil markets. Meanwhile, it may be instructive to look at North American natural gas resource estimates in a fairly traditional way.

There are two main categories of natural gas supplies. "Reserves" refers to natural gas that has been discovered and proved producible given current technology and markets. Reserves are developed as needed by drilling wells in areas that are expected to hold natural gas producing potential. Reserves are often confused with the ultimate potential natural gas "resources", which is the second category of natural gas supplies. Natural gas "resources" are more speculative than reserves. Resource estimates are more uncertain. They are based on assessment of geologic structures, not direct drilling results. Resource estimates are speculative estimates of natural gas that might be developable with known technology and at feasible costs. Reserves are more like the amount of natural gas resource that has been developed and is available to be produced within a relatively short period. Reserves should be thought of as an inventory of natural gas to be produced and marketed within a few years.

Natural gas reserves have decreased relative to consumption levels since deregulation of natural gas supplies and changes in Canadian export policies in the 1980s. Some have taken this decline as an indication that we are running out of natural gas. In reality, it is a result of reducing inventory holding costs as a response to increased competition. It is similar to the new approaches to other kinds of inventory in the modern economy where businesses hold down inventory storage time and costs. In Canada, it was also influenced by a change in a rule that required Canada to have a 20-year reserve for Canada's internal natural gas demand before any natural gas could be exported. Canadian reserves are now closer to 10 years supply.

So reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. During periods of low natural gas prices, consumption tends to increase and there is a reduced incentive to develop new reserves. Eventually, that leads to falling reserves and creates an upward pressure on prices such as the nation

[5] U.S. Geological Survey. "Coal-Bed Methane: Potential and Concerns". USGS Fact Sheet FS-123-00 (October 2000).

experienced recently. With the natural gas industry operating at narrower reserve margins, these cyclical patterns might become more severe and lead to growing natural gas price volatility.

Another common error in assessing natural gas supplies is to assume that the estimates of ultimate natural gas resources are static. In reality, natural gas resource estimates have shown a tendency to increase over time as technology improves and new discoveries are made. To illustrate this point, note that in 1964 the Potential Gas Committee, which estimates natural gas resources, estimated potential natural gas resources to be 630 trillion cubic feet. By 1996, the nation had consumed more than 630 trillion cubic feet of natural gas. If the potential resource were a fixed limit, as many interpret it, we would have run out of natural gas by now. Instead the estimated potential remaining natural gas resource in 1996, at 1038 trillion cubic feet excluding proved reserves, was actually higher than the estimate of what was remaining in 1964 in spite of over 30 years of continuing consumption.

The Potential Gas Committee estimated that in 1996 the natural gas reserves and potential resources were 1205 trillion cubic feet and noted that at current consumption rates that would be a 63-year supply. A little different approach to estimating the years that the current estimated resource would last is to look at North American natural gas resource estimates and a predicted growing natural gas consumption to see how long those supplies would last. Table 1 shows an estimate of remaining natural gas resources. Note that both of these calculations assume that potential natural gas resource estimates would not grow over time, as they have historically.

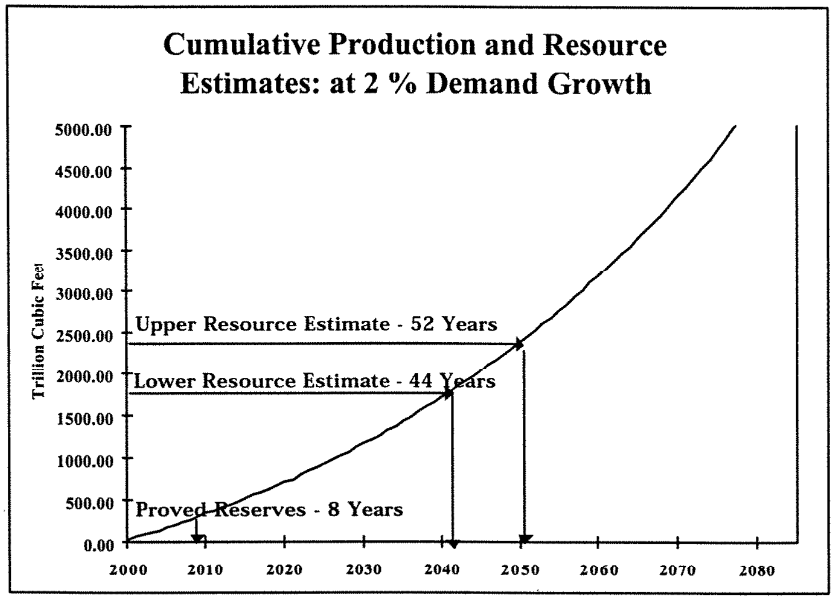
Table 1
Remaining Natural Gas Resources in North America
(Trillion Cubic Feet)

	Already Produced	Remaining Reserves	Remaining Resources
Lower 48 States	847	166	1078-1548
Alaska	0	0	237
Canada	103	51	559-630
Mexico	34	72	230-250
Total	984	289	2104-2665

Figure 4 plots the growth in cumulative natural gas consumption into the future and identifies the years when the current resource estimate would be exhausted. The Mexican consumption of natural gas and its natural gas resources have been excluded from Figure 4. U.S. and Canadian consumption is assumed to grow at 2.0 percent a year. Under these assumptions current estimated resources would last about 40 to 50 years.

However, based on past experience the resource estimates are likely to increase over time in unpredictable ways. Some examples of potential changes will give some idea of what the future could hold in the longer term for natural gas resources. As in the case of oil, many natural gas resources lie outside of North America. Currently estimated conventional natural gas resources world wide are 13,000 trillion cubic feet. As natural gas prices increase, the use of liquefied natural gas transportation will make these resources increasingly accessible to North America. As noted above natural gas occurs throughout nature in many forms. In addition to coal bed methane, there are geopressurized brines and gas hydrates.[6] The ability to recover such sources is unknown at this point, but as new sources of gas are needed in the distant future, new technologies may facilitate some use of these resources. Gas hydrates, for example, are estimated to contain from 100,000 to 300,000,000 trillion cubic feet of natural gas resource.[7]

Figure 4
Cumulative Natural Gas Production and Resources



Natural Gas Delivery

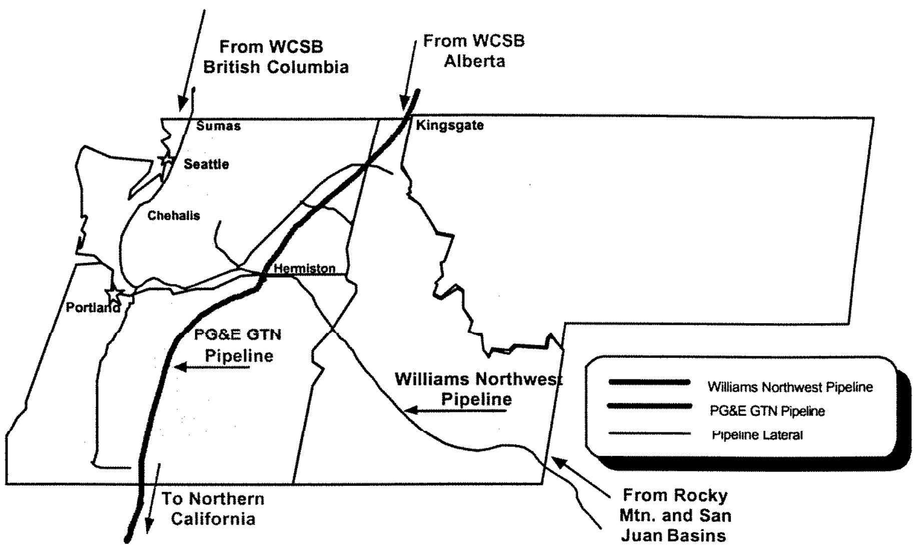
Another important consideration in natural gas supplies and cost is the capacity to transport the gas from the wells to the points of consumption. This involves gathering the gas from wells, processing the gas to remove liquids and impurities, moving the gas over long distances on interstate pipelines, and finally distribution to individual consumers home and businesses.

The sources of natural gas for the region are the Western Canada Sedimentary Basin in Alberta and Northeast British Columbia and the U.S. Rocky Mountains. Two major interstate pipelines deliver natural gas into the Pacific Northwest region from Canada. Williams Northwest pipeline brings natural gas from British Columbia producing areas through Sumas, Washington where it receives gas from the Duke Westcoast pipeline in Canada. Williams Northwest pipeline also brings U.S. Rocky Mountain natural gas into the region from its other end. Thus, Williams Northwest is a bi-directional pipline, it delivers gas from both end toward the middle. The second interstate pipeline serving the region is the PG&E Gas Transmission Northwest (GTN) pipeline, which brings Alberta supplies through Kingsgate on the Idaho - British Columbia border. Much of the gas flowing on the

[6] U.S. Geological Survey. "Describing Petroleum Reservoirs of the Future". USGS Fact Sheet FS-020-97 (January 1997).
[7] U.S. Geological Survey. "Natural Gas Hydrates - Vast Resource, Uncertain Future". USGS Fact Sheet FS-021-01 (March 2001)

GTN is destined for California. The GTN and William Northwest pipelines intersect near Stanfield, Oregon. The natural gas pipeline system serving the Pacific Northwest is illustrated in Figure 5

Figure 5
Natural Gas Pipelines Serving the Pacific Northwest



The development of interstate pipeline capacity is based on the willingness of local distribution companies or other shippers of natural gas to subscribe to capacity additions. Historically, local gas distribution companies, the regulated utilities that serve core customers' natural gas demand, have owned much of the capacity on interstate pipelines. Because residential and commercial natural gas use varies seasonally and with temperatures, there is often pipeline capacity that is available for resale. Large industrial consumers and others who have some flexibility can acquire this capacity of a short term or capacity release basis. Interruptible consumers rely on this type of pipeline and it is typically available except in extremely cold winter days.

Growing natural gas demand results in pipeline capacity expansion as it is needed and as distributors or consumers are willing to pay for the capacity on an individual contractual basis. Interstate pipeline capacity is not expanded on a speculative basis based on someone's forecast of natural gas demand. Various expansions of pipeline capacity are currently underway on both the Williams Northwest and the GTN systems as well as on other pipelines throughout the West. Most of the entities committing to these capacity expansions are electricity generators who are securing natural gas delivery capacity for proposed new electricity generating plants. Generating plant developers indicate that firm pipeline capacity is required in order to get financial backing for a new gas-fired combined cycle plant.

Over the long term it should be expected that pipeline capacity will be expanded to deliver the necessary natural gas to regional consumers. In the short term, extremely unusual natural gas demands can place severe strain on pipeline delivery capacity, which can in turn causes serious natural gas price excursions. This was the situation in the West in 2000-2001 when prices in California and the Northwest became disconnected from other U.S. prices.

Forecast Methods

Natural gas prices, as well as oil and coal prices, are forecast using an Excel spreadsheet model. The model does not address the basic supply and demand issues that underlie energy prices. Instead assumptions are made about the basic commodity price trends at a national or international level based on analysis of past price trends and market behavior and on forecasts of other organizations that specialize in such analyses. The model then converts the commodity price assumptions into wholesale prices in the Pacific Northwest and then adds transportation and distribution costs to derive estimates of retail prices to various end-use sectors.

Because natural gas is the primary end-use competitor for electricity, and because it is the electricity generation fuel of choice at this time, natural gas prices are forecast in more detail than oil and coal prices. Residential and commercial sector retail natural gas prices are based on historical retail prices compared to wellhead prices. For historical years the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences between retail and wellhead natural gas prices can be projected from historical trends, other forecasting models, or judgment.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible natural gas consumers, whether industrial or electric utility, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple markup on. For these customers, the difference between wellhead and end user prices is built up from a set of transportation cost components and regional gas price differentials appropriate to the specific type of gas use.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, firm gas supply premiums, and regional wellhead price differentials. The latter is necessary because the driving assumption is a national average wellhead gas price. Wellhead prices in British Columbia, Alberta, and the Rocky Mountains gas supply areas, the traditional sources of gas for the Pacific Northwest, have historically been lower than national averages. The fuel price model and assumptions are described in more detail in Appendix A.

Forecasts

US Wellhead Prices

There are a number of different indicators of US natural gas commodity prices. The Council's analysis utilizes two of these measures. One is the U.S. wellhead price series published by the U.S. Energy Information Administration. The other is the Henry Hub cash market price. A link between U.S. wellhead prices and the Henry Hub cash price is estimated to relate the two series for the Council's analysis.

Figure 6 shows the history of US wellhead natural gas prices from 1970 to 2001. After the deregulation of wellhead natural gas prices around 1986, natural gas prices fell dramatically to the

$2.00 per million Btu range. Since then, until 2000, natural gas prices varied between $1.60 and $2.40 in year 2000 prices. In 2000, natural gas prices shot up, reaching a peak of nearly $8.00 in January 2001. Although the 2000 price spike created expectations of significantly higher natural gas prices in the future, prices fell rapidly during 2001 and by February 2002 had returned to near their post-deregulation average of $2.15 in year 2000 prices. Many industry participants believe the lower prices this past winter were due to extremely warm temperatures and high natural gas storage inventories and that there remains an underlying shortage of natural gas supplies.[8]

The medium forecast of wellhead natural gas prices assumes that prices will average $2.70 in 2002 in year 2000 dollars. They gradually increase to $3.00 by 2005 as new gas-fired power plants come on line. After 2005, prices increase at an average annual rate of 0.5 percent through 2025. The growth rate is slightly lower than that assumed in the Council's fourth power plan, but the forecast starts at a much higher level. As a result, the draft 2015 medium forecast is $.68 higher than the 4th plan forecast. The range of the draft forecast is smaller in 2015 than in the 4th power plan; the low is higher and the high is slightly lower. This partly reflects the fact that 2015 is several years closer than it was when the 4th power plan forecast was done.

Figure 6
History US Wellhead Natural Gas Prices

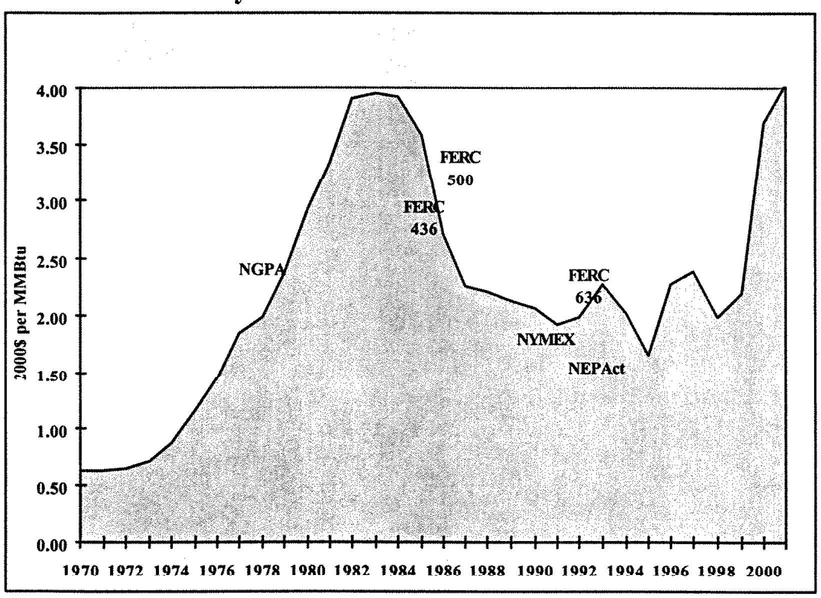


Table 2 shows actual US wellhead prices for 1999, 2000, and 2001, annual forecasts for 2002 to 2005, and forecasts in five-year intervals after 2005. The last row of Table 2 shows that average annual growth rate of real wellhead prices from 2005 to 2025. Figure 7 shows the forecast range compared to historical prices. We do not really expect future prices to follow a smooth pattern as reflected in the forecasts; they will be cyclically volatile, but the forecasts only reflect expected averages. There is, in fact, reason to expect increased volatility in natural gas prices because

[8] Natural Gas Advisory Committee, February 28, 2002

competition has narrowed reserve margins in the industry making prices more vulnerable to changes demand due to weather or other influences.[9]

The low case forecast reflects a situation where improved technology allows expanded natural gas supplies to occur with relatively moderate real price increase. Sources of natural gas would continue to be primarily from traditional natural gas sources. Low oil prices provide strong competition in the industrial boiler fuel market to help keep natural gas prices low. Continuing declines in coal prices coupled with improved environmental controls may moderate the growth in natural gas reliance for electricity generation.

The high case reflects a scenario with less successful conventional natural gas supply expansion. In the high case, higher prices would mean a growing role for frontier supply areas and liquefied natural gas imports. High prices of oil and slower progress on environmental mitigation of the effects of burning coal leave natural gas in a state of higher demand growth. Figure 7 is a graphic of the forecast range.

Table 2
US Wellhead Natural Gas Prices
(2000$ per million Btu)

Year	Low	Medlo	Medium	Medhi	High
1999	2.17	2.17	2.17	2.17	2.17
2000	3.60	3.60	3.60	3.60	3.60
2001	3.90	3.95	4.00	4.05	4.10
2002	2.35	2.45	2.70	2.80	2.90
2003	2.80	3.00	3.20	3.35	3.50
2004	2.70	2.90	3.10	3.25	3.30
2005	2.50	2.80	3.00	3.15	3.24
2010	2.30	2.60	3.00	3.20	3.40
2015	2.40	2.70	3.15	3.35	3.60
2020	2.50	2.90	3.20	3.50	3.80
2025	2.60	3.00	3.30	3.60	4.00
2005-25 Growth Rate	0.20	0.35	0.48	0.67	1.06

Figure 8 compares the draft range of natural gas price forecasts to forecasts by some other organizations. A forecast range in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2002 generally falls between our medium-low and high cases. The EIA's low to high range is based on different levels of economic growth rather than on natural gas market factors directly. A forecast by the Gas Research Institute falls near our low case in 2015, but increases to near the medium-low case by 2020. A recent draft forecast of natural gas prices by the California Energy Commission resembles our high case. Finally, a forecast by DRI-WEFA falls between our medium and medium-high cases.

[9] Natural Gas Advisory Committee, February 29, 2002

Figure 7
US Wellhead Prices: History and Forecast

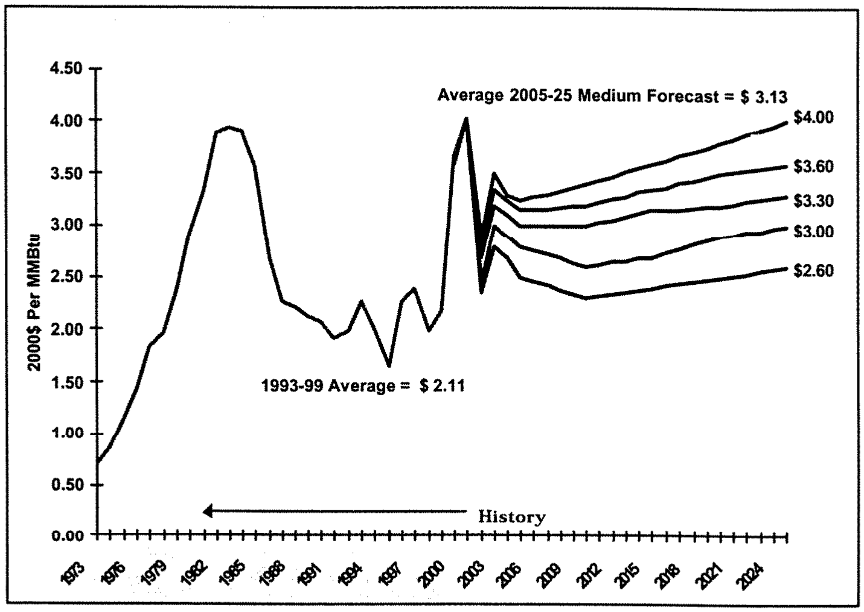
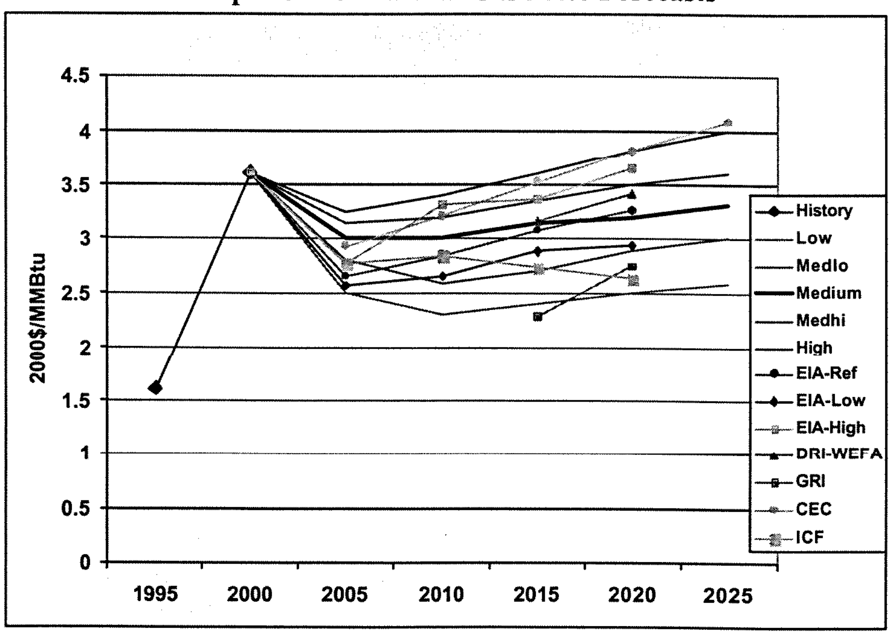


Figure 8
Comparison of Natural Gas Price Forecasts

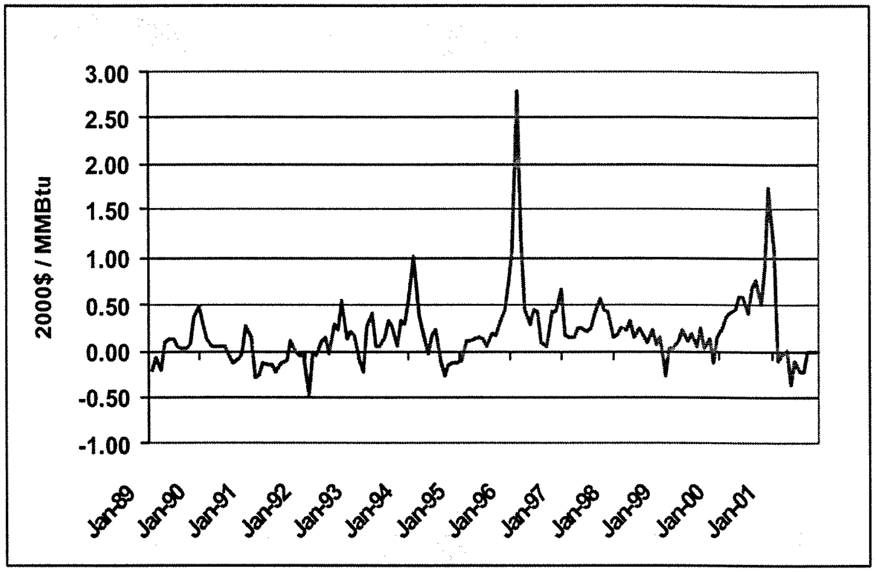


Regional Natural Gas Price Differentials

As noted above, for Aurora model analysis of electricity supplies and pricing, a forecast of Henry Hub cash market prices is used as the US commodity price. Figure 9 shows the difference between the Henry Hub price of natural gas and the US wellhead price from 1989 to late 2001. Excluding the most extreme values, the difference averaged $0.12 per million Btu. To forecast Henry Hub prices, $.12 is added to the US wellhead natural gas price.

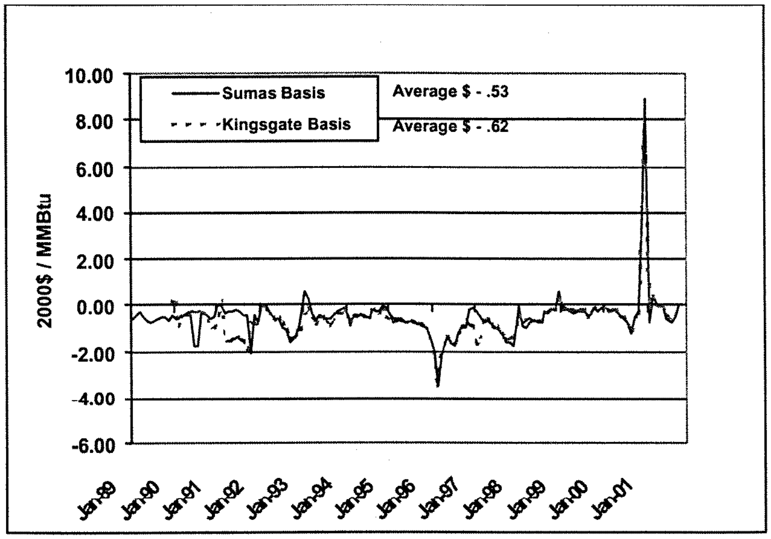
Natural gas commodity prices in the Pacific Northwest have typically been lower than the national prices.

Figure 9
Difference Between Henry Hub and US Wellhead Natural Gas Prices



During the 1990's Canadian natural gas prices delivered to the Washington border at Sumas averaged $.52 per million Btu less than the national market index at Henry Hub, Louisiana. Prices at the Canadian border at Kingsgate have averaged about $.10 lower than the Washington border price at Sumas. As shown in Figure 10, however, these regional price differentials have been extremely volatile. Figure 10 shows monthly regional price differentials from Henry Hub to Sumas and Kingsgate during the 1990s. Occasionally, regional natural gas prices have even been above Henry Hub prices. In December of 2000 they were dramatically so, reflecting regional pipeline constraints caused, in part, by the electricity crisis in the West and the sudden increase in the use of natural gas to generate electricity. The average differentials above exclude the extreme values in the winter of 1995-96 and 2000-01.

Figure 10
Canadian Gas Price Differentials from Henry Hub



For purposes of forecasting regional natural gas prices, a liquid pricing point in Alberta called the AECO-C hub is used as a focal point for regional natural gas prices. AECO-C prices have averaged $.72 per million Btu (2000 dollars) less than Henry Hub prices in recent years. Prices at other points in the Northwest are estimated relative to AECO-C. The emerging natural gas pricing point in British Columbia is Station 2 in Northeastern British Columbia. It is assumed that on average Station 2 prices will be $.10 per million Btu higher than at AECO-C. However, these differentials are expected to be seasonal with prices being the same during the summer season and Station 2 being $.20 higher during the winter.

There is uncertainty about the future natural gas price differential between the AECO-C hub and the average Henry Hub. In the forecasts, this differential is varied among the forecast cases. The forecasts assume that the basis differential will decrease from historical averages. This assumption reflects expected growth in pipeline capacity to further integrate the Rocky Mountain and Western Canada Sedimentary Basin natural gas supplies into the national market. However, distances to markets and relatively low cost natural gas supplies in the West are expected to cause a continuing differential between national prices and Pacific Northwest prices as measured at AECO-C. Table 3 shows the assumptions for the five forecast cases.

Table 3
Price Differentials Between the AECO-C and Henry Hub

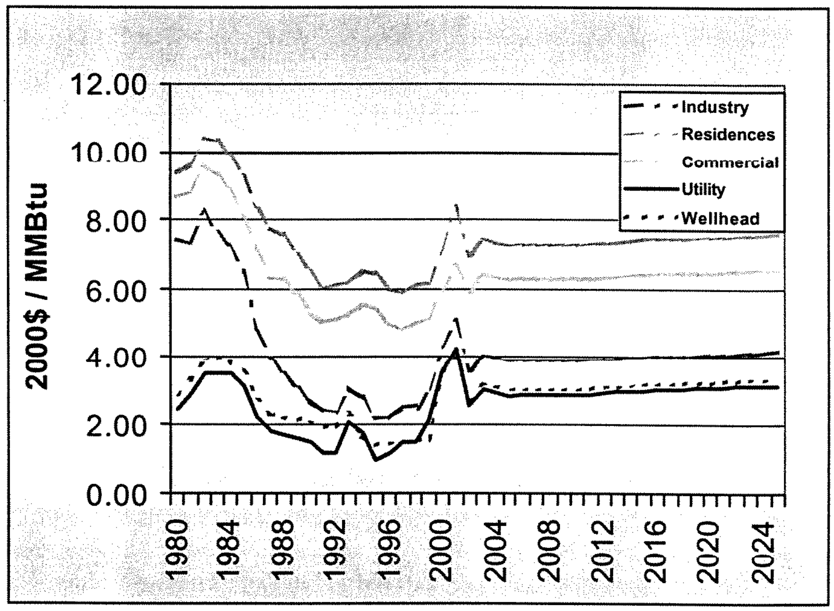
Forecast Case	2000 $ per Million Btu
Low	$ - .60
Medium Low	$ - .55
Medium	$ - .45
Medium High	$ - .30
High	$ - .20

Retail Prices

The prices paid by regional consumers of natural gas are forecast based on the U.S. and Canadian commodity prices described in the previous section. The exact method depends on the consuming sector being considered and will be explained below.

Figure 11 shows the regional retail natural gas price forecasts for end-use sectors compared to the U.S. wellhead price forecast for the medium case. The residential and commercial forecasts are based on historical differences between regional retail and U.S. wellhead prices. Industrial price forecasts are a weighted average of three different price estimates; off-system firm gas, off-system interruptible gas, and local distribution company-served industrial customers. Off-system gas is gas supply that is purchased directly by industrial customers instead of from local gas distribution companies. The ability for industrial users to purchase natural gas directly in the market began with natural gas deregulation in the mid-1980s. The effect on industrial prices is apparent in Figure 11, where the average industrial price moves toward the utility and wellhead price and away from the utility served residential and commercial prices during the 1980s. The differences between U.S. wellhead and regional retail prices are discussed further below.

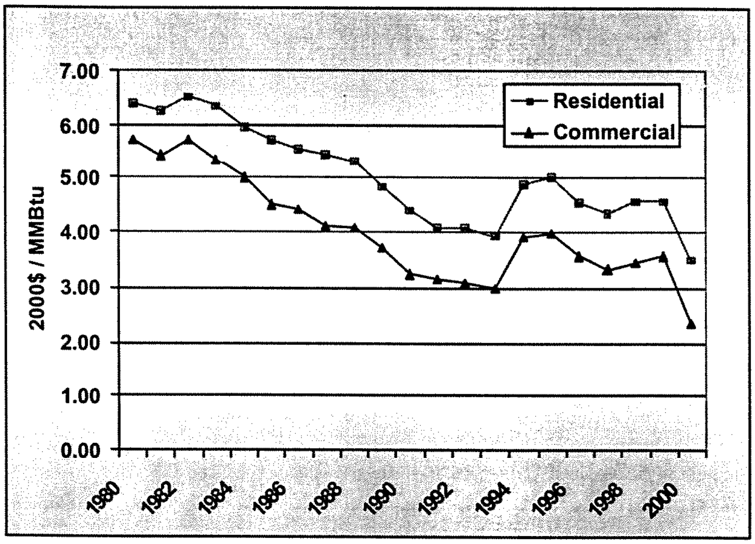
Figure 11
Retail and Wellhead Prices History and Medium Forecast



Residential and commercial sector prices are based on observed differences from U.S. wellhead natural gas prices between 1989 and 2000. Figure 12 shows that these differences declined during the 1980s. Since then, the differences have leveled off. The forecast assumes a $4.25 difference for residential and a $3.25 difference for commercial. These differences are held constant over the forecast period and across forecast cases.

As noted above the industrial price shown in Figure 11 is a blended price. The prices of the three components are derived in different ways. The on-system prices are developed in the same way as residential and commercial prices. The forecast addition to U.S. wellhead prices to estimate on-system retail prices starts at about $1.70, but, unlike the residential and commercial adders, declines gradually over time. It does not, however, vary among forecast cases.

Figure 12
Difference Between Regional Retail Natural Gas Prices and US Wellhead Prices



Off-system industrial natural gas prices are built up from wellhead prices using estimates of the various components of gas supply and transportation costs. These components are described in detail in the Appendix A, but Table 4 shows an example of industrial off-system regional price estimation for 2010 in the medium case forecast. The example is a large high-capacity factor industrial consumer on the West side of the Cascade Mountains. There is some disagreement whether a consumer who buys natural gas supplies on a firm basis would generally pay a premium of for firm supplies. In this draft it is assumed that there is no premium. It is assumed that a large capacity factor industrial consumer would likely pay a negotiated rate for gas transportation by the local distribution utility and there is no differential assumed for firm versus interruptible distribution service for such customers.

To combine the components into a blended price it is assumed that 30 percent of industrial natural gas consumption is purchased from the local distribution utility. The remaining 70 percent is purchased directly by industrial consumers. 90 percent of these direct purchases are assumed to be interruptible. As can be seen in Figure 11, the average difference between the US wellhead price and the blended industrial users' price is small compared to the residential and commercial sectors. It is important to remember that the differences include a negative adjustment of $.32 for the regional commodity price differential described in the previous section.

Table 4
Estimation of West-Side Industrial Off-System Firm and Interruptible Natural Gas Cost
(2000 $ / MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry Hub Price		$ 3.12	$3.12
Station 2 Price Differential	$ - .35	2.77	2.77
In Kind Fuel Cost	+ 4.24%	2.89	2.89
Firm Pipeline Capacity (Rolled-in)	+ .45	3.34	
Interruptible Pipeline Capacity	+ .34		3.23
Pipeline Commodity Charge	$ + .06	3.40	3.29
Firm Supply Premium	$ + 0.0	3.40	
LDC Distribution Cost	+ .20	$ 3.60	$ 3.49

Natural gas prices for electricity generators reflect the assumption that all electricity generators will buy their gas directly from suppliers rather than the local utility and that generators will receive their gas supplies directly from interstate pipelines. Like industrial direct purchases, these purchases can be made on a firm or interruptible basis. In the draft forecast, it is assumed that all electric generator gas purchases are made on a firm transportation basis. Electric generator natural gas prices are calculated both in terms of average cost per million Btu, and in terms of fixed and variable natural gas costs. Again these assumptions are detailed in the Appendix A. Table 5 shows an example of the calculation for a new generating plant on the east side of the Cascade Mountains. The example is for the year 2010 in the medium forecast case.

Table 5
Estimation of Utility Firm and Interruptible Natural Gas Cost
(2000 $ / MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Wellhead Price		$ 3.12	$ 3.12
AECO Price Differential	$ - .45	2.67	2.67
In-Kind Fuel Charge	+ 2.5%	2.74	2.74
Firm Pipeline Capacity (Incremental)	$ + .41	3.15	
Interruptible Pipeline Capacity	$ + .23		2.97
Pipeline Commodity Charge	$ + .01	3.16	2.98
Firm Supply Premium	$ + .00	3.16	

Inputs to the Aurora model are configured differently, but they are based on the same underlying U.S. wellhead price forecast. Adjustment factors from US wellhead prices to Aurora market area prices are described in Appendix B. In addition, price forecasts are being revised to reflect seasonal differences in natural gas delivered costs.

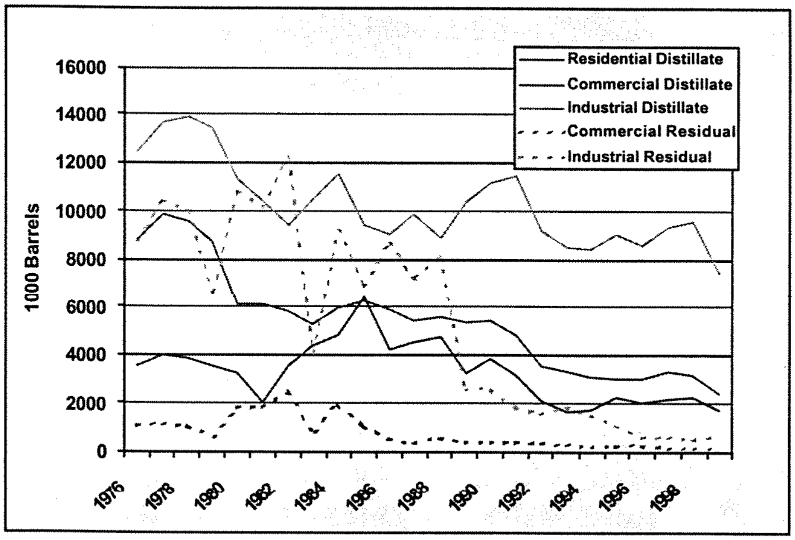
Oil

Historical Consumption and Price

Oil products are playing a decreasing role in both electricity generation and in residential and commercial space heating in the Pacific Northwest. Figure 13 shows that both distillate and residual oil consumption have generally been declining in all sectors since the mid-1970s.

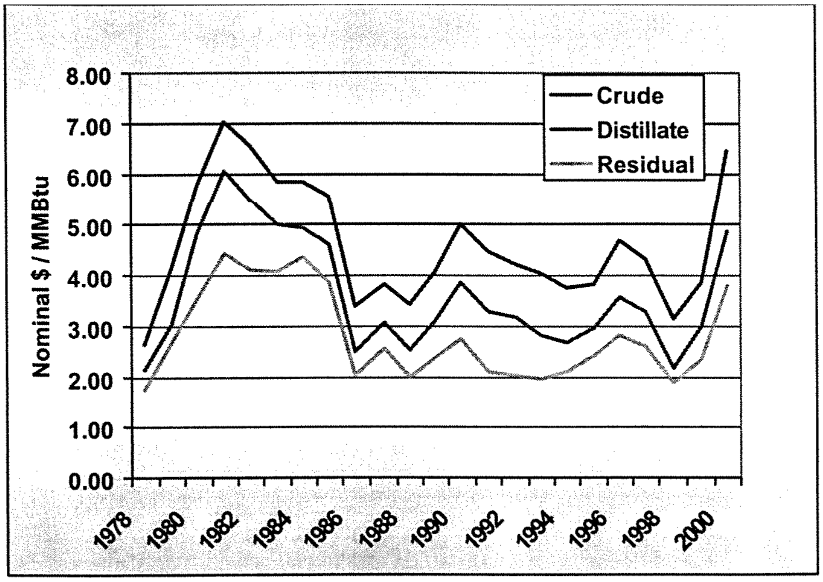
To a large extent, declining oil consumption reflects growing natural gas use. Some increases in oil consumption are evident during the mid-1980s when natural gas prices were high. Substitution possibilities between natural gas and oil use in large industrial applications is a key feature of fuel markets. The substitution of oil for natural gas, for example, played an important role during the past year in reducing high natural gas prices. In the Pacific Northwest, the displacement of industrial residual oil use is particularly dramatic as shown in Figure 13.

Figure 13
Historical Oil Consumption in the Pacific Northwest



In general, the price of oil products is determined by the world price of crude oil. Figure 14 shows crude oil prices from 1978 to 2000 compared to refiner prices for residual oil and distillate oil. The differences are relatively stable with residual oil being priced lower than crude oil and distillate oil higher. On average, during this time period distillate oil was priced $1.00 per million Btu higher than crude oil. Residual oil was on average priced $.80 lower than crude oil. (Prices are in nominal dollars.) Retail prices of oil products follow very similar patterns, but at different levels.

Figure 14
Comparison of Crude Oil and Refiner Product Prices



Methods

The forecasts of oil prices are based on assumptions about the future world price of crude oil. Refiner prices of distillate and residual oil are derived from formulas relating product prices to crude oil prices and refining costs. The formulas are based on a conceptual model of refinery costs and assume profit maximizing decisions by refiners regarding the mix of distillate and residual oil production. Appendix A describes this model in more detail.

Although the refinery model is very simple, and the refining cost estimates and energy penalties have not been changed since the early days of the Council's planning, the ability of the equations to simulate historical prices remains good. Figures 15a and 15b show a comparison of predicted residual oil and distillate oil prices, respectively, based on actual world crude oil prices to actual prices from 1978 to 2000. The equations appear to be predicting well, especially after the mid-1980s.

Forecasts of retail oil prices to the end-use sectors are based on historical differences between the refiner price estimates for residual and distillate oil and actual retail prices. These markups are assumed constant over time and across alternative forecast cases.

Figure 15a
Comparison of Forecast and Actual Residual Oil Prices

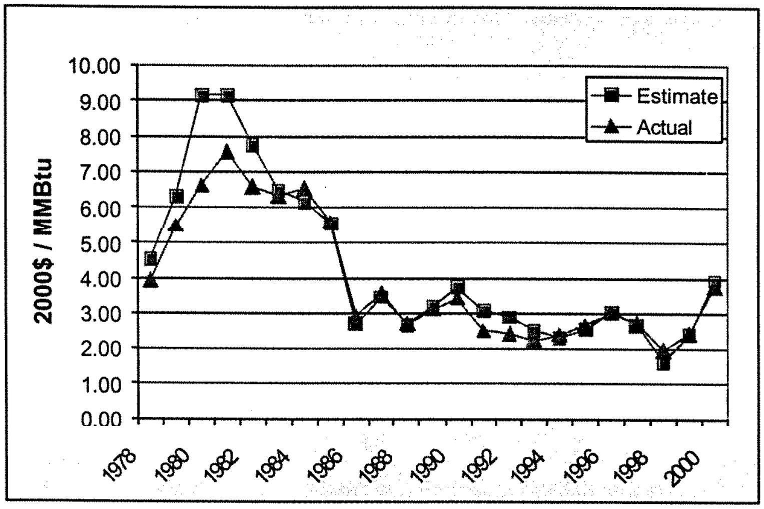
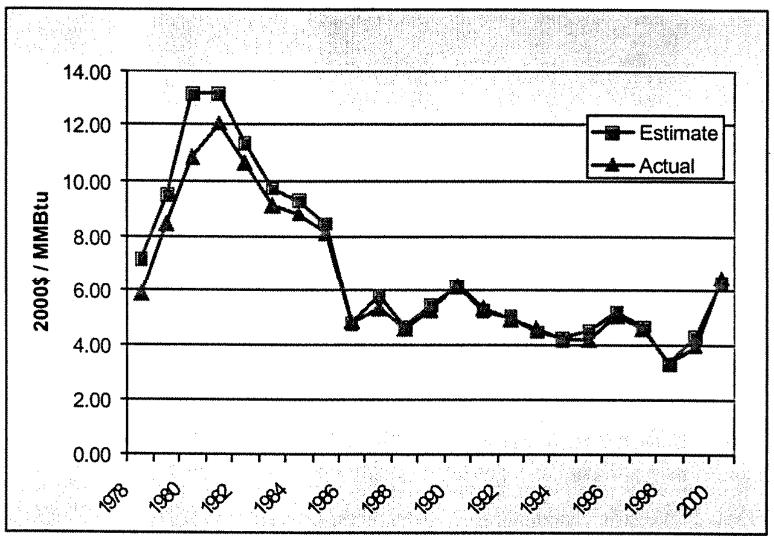


Figure 15b
Comparison of Forecast and Actual Distillate Oil Prices



World Crude Oil Price Forecast

The situation in world oil markets is very different from natural gas markets. Oil is much more of a world market than natural gas due to the easier transportability of oil. The world's proved reserves of oil are about 1000 billion barrels. World consumption of oil in 2000 was 27 billion barrels. (Based on BP and USGS data on web) Oil reserves are dominated by the Middle East, which has 65 percent of the world's proven reserves. The Middle East's reserves can be produced at low cost, but the middle eastern countries and their partners in the Organization of Petroleum Exporting Countries (OPEC) attempt to limit production so that world oil prices remain in the range of $20 to $30 per barrel. Proven oil reserves in the Middle East are 80 times the actual production rate in 2000. As a result, world oil prices are likely to depend on OPEC actions for the duration of the forecast period.

Although fluctuating world oil demand, Middleeast conflicts, and lapses in OPEC production discipline will result in volatile oil prices over time, we have assumed a range of stable average prices in the forecast. Figure 16 shows historical world oil prices and the five forecast cases.

Since the mid 1980s, world oil prices have averaged $21 a barrel in year $2000 prices. However, they varied from a low of $12.49 per barrel in 1998 to $27.69 in 2000. During 2001 prices fell back to near $20. Table 6 shows world oil price forecasts for individual years between 2000 and 2005 and in five-year increments thereafter. The forecasts all have moderate real oil price growth after 2005, reflecting a growing need to invest to increase production capacity over time. Generally, it is assumed that lower prices in the early years of the forecast will require greater rates of price increase over time as costs of investment in capacity expansion are a larger share of price. That is,near-term higher prices could support future capacity investments with less price increase over time.

Figure 16
World Oil Price: History and Forecasts

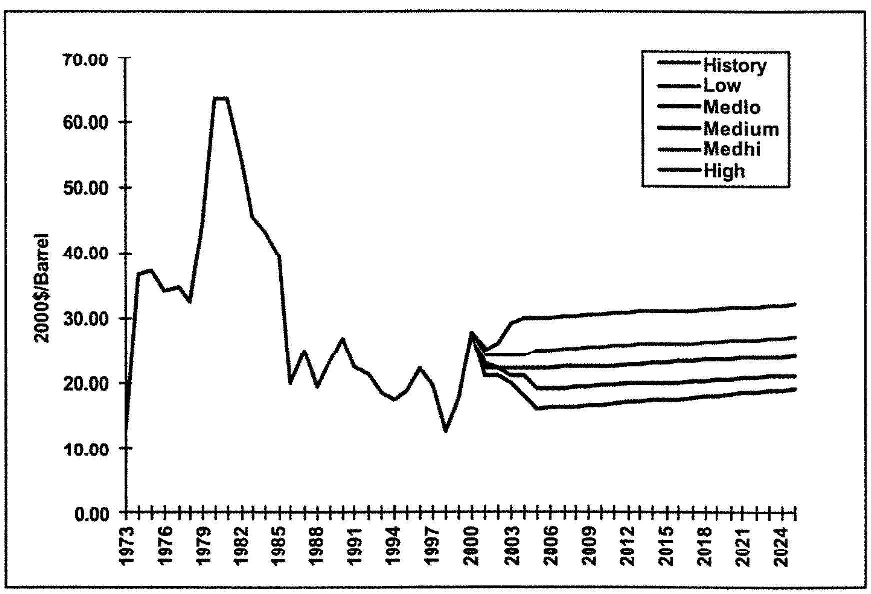


Table 6
World Oil Price Forecasts
(2000$ per MMBtu)

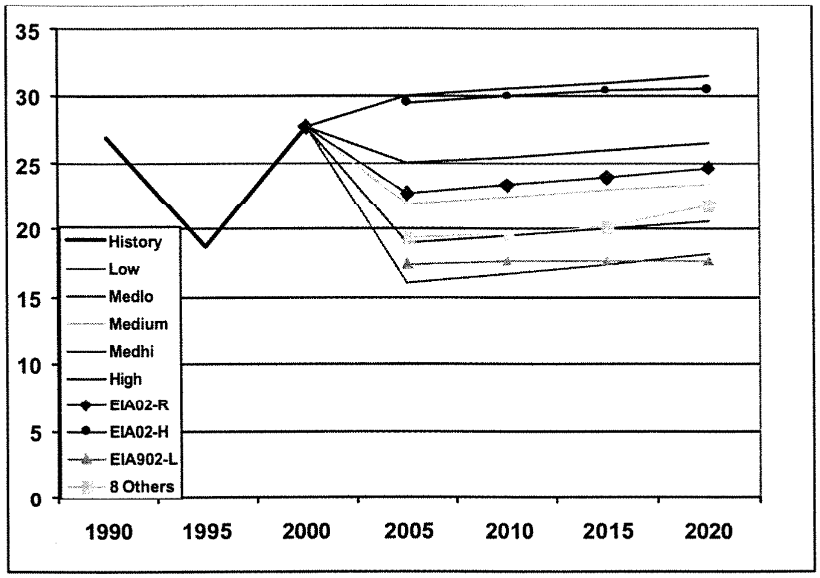
	Low	Medium-Low	Medium	Medium-High	High
2000	**27.69**	**27.69**	**27.69**	**27.69**	**27.69**
2001	**21.00**	**22.00**	**23.00**	**24.00**	**25.00**
2002	**21.00**	**22.00**	**22.00**	**24.00**	**26.00**
2003	**20.00**	**21.00**	**22.00**	**24.00**	**29.00**
2004	**18.00**	**21.00**	**22.00**	**24.00**	**30.00**
2005	**16.00**	**19.00**	**22.00**	**25.00**	**30.00**
2010	**16.70**	**19.50**	**22.50**	**25.50**	**30.50**
2015	**17.40**	**20.00**	**23.00**	**26.00**	**31.00**
2020	**18.20**	**20.50**	**23.50**	**26.50**	**31.50**
2025	**19.00**	**21.00**	**24.00**	**27.00**	**32.00**

The assumptions about future oil prices are based on observation and analysis of historical prices and on comparisons among forecasts made by other organizations that put substantial resources into analysis of future price trends. Figure 17 shows world oil prices for 1990, 1995 and 2000 compared to the forecast range and a range of other forecasts. The U.S. Energy Information Administration (EIA) is the source of the summary of other forecasts.[10] Figure 17 shows EIA's forecast range and the average of 8 other forecasts that EIA compared to their own forecast. EIA's reference case forecast falls just above our medium case. EIA's range is also very similar our low to high range. The average of the 8 other forecasts falls along our medium-low forecast until 2015 and then moves a little higher for 2020.

In the Council's 4th power plan, world oil price forecasts were assumed to grow over time in constant dollars. The 2005 levels were very similar to the assumptions above, however, by 2015 the prices had grown to be higher than the draft forecasts in Figure 17. The differences are between $1 and $3 in 2015 depending on the forecast case.

[10] U.S. Energy Information Administration, Annual Energy Outlook 2002.

Figure 17
Comparison to Other World Oil Price Forecasts



Consumer Prices

Using the methods described earlier, world oil price forecasts are converted to refiner prices of residual oil and distillate oil. Figure 18 shows the forecast relationship among these products for the medium case. A set of markups is used to derive forecasts of retail prices for various products to end use sectors. These retail markups, shown in Table 7, are generally assumed constant over time and across forecast cases. The markups are based on historical average price relationships during the 1980s and 1990s.

Figure 18
Refiner Prices of Residual and Distillate Oil Compared to World Crude Oil Price
(Medium Case)

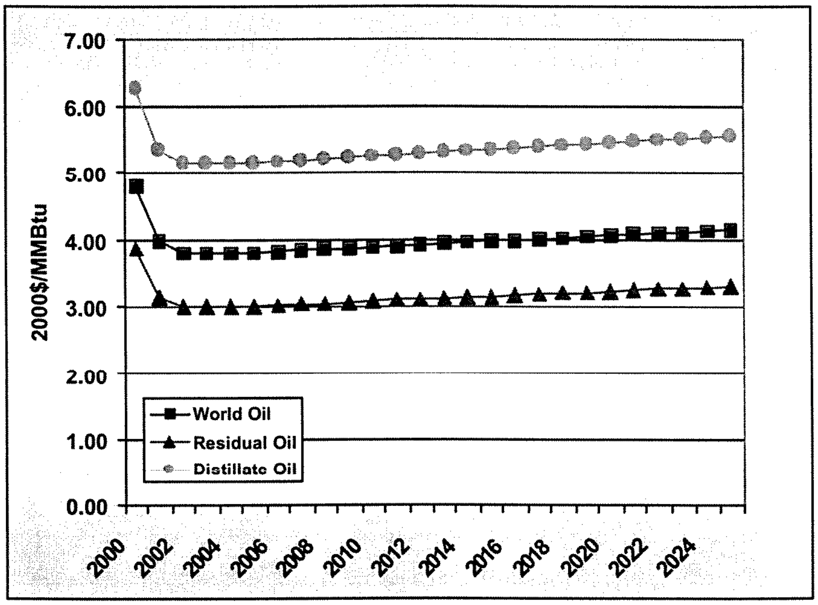


Table 7
Retail Markup Assumptions for Oil Products and Sectors

INDUSTRIAL SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ 1.00
UTILITY SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ .46
COMMERCIAL SECTOR	
Residual Oil Over Industrial	$ .05
Distillate Oil Over Industrial	$ -.42
RESIDENTIAL SECTOR	
Distillate Oil Over Industrial	$ 1.98

Coal Price Forecasts

Coal prices play little role in determining regional electricity demand. There are not many end uses where coal and electricity substitute for one another and coal consumption is relatively minor in the Pacific Northwest in any case. Coal as a percent of total industrial fuel purchases in the region in 1999 was 0.7 percent compared to 6.1 percent for the US as a whole. Coal is also a relatively minor electricity generation fuel in the region compared to the US. In 1999, coal accounted for 14 percent of regional utility fuel purchases compared to 55 percent for the nation. Only Montana had a coal generation share similar to the US for electricity generation.

Nevertheless, coal may be important alternative as an electricity generation fuel in the future. The trade-off is that while coal is a plentiful and relatively inexpensive domestic energy source, it also has substantial environmental impacts both during extraction and burning. Thus its future may depend on technological progress in emissions controls and policies with regard to air quality and global warming.

Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[11] One measure is "demonstrated reserve base", which measures coal more likely to be mined based on seam thickness and depth. EIA estimates that the 1997 U.S. demonstrated reserve base of coal is 508 billion short tons. Only 275 short tons of these resources are considered "recoverable" due to inaccessibility or losses in the mining process. This is a large supply of coal relative to the current production of about 1 billion short tons a year.

About half of the demonstrated reserve base of coal, 240 billion short tons is located in the West. Western coal production has been growing due to several advantages that it has over Appalachian and Interior deposits. Western coal is cheaper to mine due to its relatively shallow depths and thick seams. More important recently is that Western Coal is lower in sulfur content. Use of low sulfur coal supplies has been an attractive way to help utilities meet increased restrictions on SO2 emissions under the 1990 Clean Air Act Amendments that took effect on January 1, 2000. The other characteristic that distinguishes most Western coal from Eastern and interior supplies is its Btu content. Western coal is predominately sub bituminous coal with average heat contents of about 17 million Btus per short ton. In contrast, Appalachian and Interior coal tends to be predominately higher grade bituminous coal with heat rates averaging about 24 million Btus per short ton.

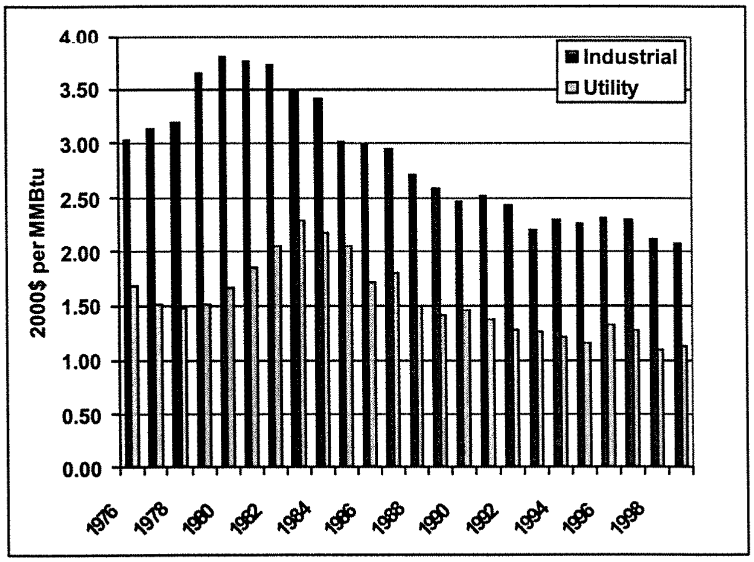
Western coal production in 2000 was 510.7 million short tons. Two thirds of that production came from Wyoming, 338.9 million short tons. The second largest state producer was Montana at 38.4 million tons. Colorado, New Mexico, North Dakota and Utah produced between 26 and 31 million short tons each and Arizona produced about 13 million short tons.

Productivity increases have been rapid, especially in Western coal mines. As a result, minemouth coal prices have decreased over time. In constant dollars, Western minemouth coal prices declined by nearly 6 percent per year between 1985 and 2000.

The price of delivered coal is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from minemouth costs due to long-term coal supply contracts. Figure 19 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 1999.[12] Coal prices increased during the late 1970s with other energy prices, but since the early 1980s have declined steadily. On average, regional industrial coal prices decreased at an annual rate of 3.2 percent between 1980 and 1999. Regional utility coal prices have followed a similar pattern of decline, although utility prices were delayed a few years in following industrial prices downward. This may have been due to longer-term coal contracts for the coal-fired generation plants in the region.

[11] U.S. Energy Information Administration, U.S. Coal Reserves: 1997 Update, February 1999.
[12] U.S. Energy Information Administration

Figure 19
Pacific Northwest Industrial and Utility Historical Coal Price Trends



Forecasts of coal prices follow a very simple method. Different constant rates of price decline for Western minemouth coal prices are assumed for the five forecast cases. The assumptions are shown in Table 8. In all cases, coal prices are assumed to decline more slowly than they did during the previous 15 years.

Table 8
Assumed Western Minemouth Coal Price Growth Rates

Forecast Case	Average Annual Rate of Growth
Low	- 1.5 %
Medium Low	- 1.1 %
Medium	- 0.8 %
Medium High	- 0.5 %
High	+0.1 %

Delivered prices to Pacific Northwest industries and utilities are estimated by applying fixed markups from Western minemouth prices to delivered prices. Transportation costs are significant for coal. States that are farther away from the mines tend to have significantly higher delivered coal costs. Montana and Wyoming delivered costs, however, can be quite close to the minemouth price. Some coal-fired electricity generating plants are located at the mine and have little, if any, transportation cost. In more distant states, like Washington, the delivered cost can be more than 3 times the minemouth price. Table 9 shows the additions to western minemouth coal prices for the states in the West and the 2010 medium forecast of coal prices that result.

Table 9
Derivation of State Electricity Generator Coal Prices, 2010 Medium Forecast
(2000 Dollars per Short Ton)

	Markup from Mine	Price Forecast
Western Minemouth		$ 0.47
Washington	$ + 1.04	1.51
Oregon	+ .53	1.00
Idaho	+ .45	.92
Montana	+ .20	.67
Utah	+ .65	1.12
Wyoming	+ .28	.75
Colorado	+ .50	.97
New Mexico	+ .87	1.34
Arizona	+ .84	1.31
Nevada	+.89	1.36

Appendix A - Fuel Price Forecasting Model

Introduction

This paper describes the fuel price forecasting model that was used for the Council's 2001, or 5th power plan. The model consists of several worksheets linked together in an EXCEL "workbook". The Excel model is in Q:\TM\FUEL\MODF\FUELMOD02.

The model includes forecasts of natural gas, oil and coal prices. However, the natural gas price model is the most detailed of the three by far. Retail fuel prices for the various demand sectors are derived from the forecasts of basic energy commodity prices, that is, the world price of oil, the average wellhead price of natural gas, and western minemouth coal prices. These energy prices are forecast by several organizations that specialize in energy market forecasting. Thus basic energy price trends can be compared to a variety of forecasts which helps define a range of possible futures based on much more detailed modeling and analysis than the Council has the resources to accomplish alone. The prices of oil, natural gas, and coal, are not explicitly linked to one another. Rather, the relationships should be considered by the analyst in developing fuel price scenarios.

Retail prices are estimated by adding cost components to the basic energy commodity prices. Where possible these additional costs, or markups, are based on historical relationships among energy costs to various sectors. Thus, the basic driving forces in the fuel price model are world oil price forecasts, wellhead natural gas price forecasts, coal price growth rates, and markups to retail prices in various end-use sectors .

The degree of detail devoted to each fuel depends on its relative importance to electricity planning. For example, natural gas is a very important determinant of both electricity demand and the cost of electricity generation from gas-fired plants. As a result, the natural gas forecasting approach is significantly more detailed than oil or coal. Oil plays a smaller role in competition with electricity use and in electricity generation and receives less attention. Coal plays little role in determining electricity demand and is treated very briefly in the model using assumed annual growth rates.

Model Components

Historical retail data for each fuel are kept on separate Excel files called OIL.XLS, GAS.XLS, and COAL.XLS. These spreadsheets contain historical retail price data by state and consuming sector from the "State Energy Price and Expenditure Report" compiled by the U.S. Energy Information Administration (EIA). In addition, they contain consumption data from the "State Energy Data Report", also published by EIA. The spreadsheets convert the prices to real 2000 dollars and calculate consumption weighted average regional prices for each end-use sector.

WOPFC and NGFC are tabs in the FUELMOD01 Excel Workbook where forecasts of world oil prices and natural gas wellhead prices, respectively, are developed. They take historical data consistent with the historical fuel price worksheets described in the previous paragraph and merge it with forecasts in five year intervals. The worksheet interpolates between the five year forecasts to get annual values. These tabs also contain previous Council forecasts and forecasts by other organizations for comparison purposes.

MAIN contains the forecasts of basic oil and gas commodity prices calculated in WOPFC and NGFC and any other scenario dependent assumptions and parameters. It also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices. Wellhead gas prices feed into the gas price model and world oil prices feed into the oil price model. MAIN contains the scenario controls and variables for the entire model. The varying scenario assumptions and their cell locations are as follows:

Scenario Name	B2
Wellhead Natural Gas Price	B30:B54
World Oil Price	C30:C54
LDC Firm Distribution Charge	E9:E54
Regional Wellhead Differential	F9:F54
Real Growth Rate of Incremental Pipeline Costs	D60
Coal Price Growth Rate	D61
Firm Natural Gas Supply Share	D62

The separate tabs in FUELMOD01 are described at the end of this appendix in a section entitled Model Components, which is a printout of the first tab ("DOC") in the model. The model structure is described in more detail below.

Natural Gas Model

The natural gas price forecasting component is far more detailed than the oil or coal components. This is not only because natural gas is currently the strongest competitor to electricity, but also because of the lack of reliable historical price information for large industrial and electric utility gas purchases.

There are four separate worksheets for natural gas price forecasts by sector; INDUST which contains industrial sector forecasts, NWUTIL which contains electricity generator forecasts, RES_COM which contains residential and commercial forecasts, and SWEG which contains Southwest electric utility gas prices. A separate worksheet, COMPONENTS, supports the industrial and electricity generator forecasts by calculating the various components of cost that are incurred between the wellhead and the end user. The worksheet GASSUM is simply a report that summarizes the natural gas price forecasts.

Residential and commercial sector gas prices are based on historical retail prices compared to U.S. wellhead prices. For historical years the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences, or markup, can be projected from historical trends, other forecasting models, or judgement.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible customers, whether industrial or electricity generators, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple markup on. For these customers, the difference between wellhead and end user prices is built up from a set of transportation cost components appropriate to the specific type of gas use. These components are developed in the worksheet COMPONENTS.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, firm gas supply premiums, and regional wellhead price differences. The latter is necessary because the driving assumption is a U.S. average wellhead gas price. Wellhead prices in British Columbia, Alberta, and the Rocky Mountains gas supply areas, the traditional sources of gas for the Pacific Northwest, have historically been lower than national averages.

Tables A-1 and A-2 show the various transportation components, their column location in the COMPONENTS worksheet, and the current value or range of values in the model. Table A-1 applies to a large natural gas consumer on the west side of the Cascades and Table A-2 applies to the same kind of consumer on the east side

Table A-1
West-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Markup Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead to Henry Hub	C9	$ +.12					
Henry Hub to AECO	D		- .60	- .55	- .45	- .30	- .20
AECO to Station 2 *	E	+ .10					
Pipeline Capacity Cost							
Firm Rolled-In	F	+ .45					
Firm Incremental	H	+.60 in 2004 + growth	0.0	0.3	0.7	1.0	1.3
Interruptible *	J	+ .34					
Pipeline Commodity Cost	L	+ .06					
Pipeline In -Kind Fuel Cost *	F61	+ 4.24 %					
LDC Distribution Cost	N	+ .20					
Firm Supply Premium	O	+ 0.0					

* Summer and winter values are different from the averages show here

Table A-2
East-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Markup Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead to Henry Hub	C9	$ +.12					
Henry Hub to AECO	D		- .60	- .55	- .45	- .30	- .20
Pipeline Capacity Cost							
Firm Rolled-In	G	+ .28					
Firm Incremental	I	+.40 in 2006 + growth	0.0	0.3	0.7	1.0	1.3
Interruptible *	K	+ .23					
Pipeline Commodity Cost	M	+ .01					
Pipeline In -Kind Fuel Cost *	F62	+ 2.5 %					
LDC Distribution Cost	N	+ .20					
Firm Supply Premium	O	+ 0.0					

* Summer and winter values are different from the averages show here

The resource planning models require utility gas prices in terms of their fixed and variable components. Wellhead prices adjusted for regional differences, pipeline fuel costs, and pipeline commodity charges are variable costs, that is they can be avoided if electricity is not generated. In addition, some portion of the pipeline capacity charge may be avoided through resale in the capacity release market. The share of firm pipeline capacity costs that can be recovered by resale in the capacity release market is a parameter in the model and is currently assumed to equal .50. For example, if it were not possible to recover any pipeline capacity costs then they become fixed costs. The other potentially fixed cost is any premium that must be paid to secure firm gas supply, but this is currently assumed to be zero. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

Oil Model

The oil price forecasting model first estimates the refiner price of distillate and residual oil based on the assumed world price for crude oil. This is done using a very simple model of refinery economics.[13] Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding markups based on the historical difference between calculated refiner wholesale prices and actual retail prices.

The simple model of refiner economics considers the cost of crude oil, the cost of refining crude oil into heavy and light oil products, and the value of those products in the market. It assumes that refiners will decide on their production mix so that their profits will be maximized. That is, the difference between the revenue received from sale of products and the costs of crude oil and refining it into products will be maximized.

The underlying assumptions are as follows:

Refining costs:

Simple refining
- $2.15 per barrel in 2000 dollars.
- Saudi light yields 47 % heavy oil.
- 3 percent energy penalty.

Complex refining
- $5.38 per barrel in 2000 dollars.
- yield 100 percent light oil.
- 12 percent energy penalty, about 6-8 percent above simple refining.

Desulpherization
- $3.91 per barrel in 2000 dollars.
- 4 to - 8 percent energy penalty.
- Assumed not to be necessary in NW.

Profit Equations:

Simple refinery

Revenue = .47H + .53L
Cost = C + .03C + 2.15
Profit = (.47H + .53L) - (C + .03C + 2.15)

Where:
.47 is residual oil output share.
.53 is distillate oil output share.
H is residual oil wholesale price.
L is distillate oil wholesale price.
C is cost of crude oil
.03 is the energy penalty for simple refining.

[13]This refinery model evolved from the old Council fuel price forecasting method developed by Energy Analysis and Planning, Inc. That company has evolved into Economic Insight Inc.

2.15 is the refining cost per barrel.

Complex refinery

Revenue $= L$
Cost $= C + .12C + 5.38$
Profit $= L - (C + .12C + 5.38)$

Equilibrium Condition: Profit from heavy products equals profit from light products at the margin.

$$.47H + .53L - C - .03C - 2.15 = L - C - .12C - 5.38$$

Solve for product prices:

$$.47H + .53L - L = .03C - .12C - 5.38 + 2.15$$

$$.47(H - L) = -.09C - 3.23$$

$$(H - L) = -.1915C - 6.8723$$

Using $L = C + .12C + 5.38$ gives

$$H = -.1915C - 6.8723 + C + .12C + 5.38$$

$$H = .9285C - 1.5133$$ (Equation for residual oil price as a function of crude oil price.)

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (in 2000 dollars) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based markup are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices and then consumption weighted to get an average oil price for the sector. The residential sector does not use residual oil so only a distillate retail price is calculated.

Coal Model

The coal model is a very simple approach. Average Western minemouth coal prices are forecast by applying assumed, scenario specific, growth rates to a base year level. Regional utility and industry prices, and state-specific utility prices are forecast based on time- invariant differentials from western the minemouth prices.

MODEL COMPONENTS
(Tabs in the Excel Workbook)

DOC	-- Describes files in the forecast model
NGFC	-- Contains historical prices and the forecast range of wellhead gas prices. Scenarios are to be copied into MAIN for each case. Contains GDP deflators for converting historical to study year dollars.
WOPFC	-- Contains historical prices and the forecast range of world oil prices. Scenarios are to be copied into MAIN for each case.
MAIN	-- Contains drivers for forecast model and includes scenario variant values. (Avg. wellhead, world oil, GNP deflators etc. Displays boiler fuel relative gas, oil, coal prices
MARKUP	-- Combines the various components of pipeline and distribution cost, regional wellhead price difference, and other add-ons to the wellhead gas price. These adders are used in the INDUST and NWUTIL sheets.
Basis	-- Contains regional basis differential assumptions for each scenario To be copied into MAIN for each scenario.
RES_COM	-- Residential & Commercial gas price model, linked to MAIN wellhead prices by retail price differences.
INDUST	-- Industrial gas price model, linked to MAIN wellhead Large interruptible, Avg. transport, through LDC & Mixed
NWUTIL	-- PNW Utility gas price model, linked to MAIN wellhead Interruptible and Firm burner-tip
00$ NWUtil	Shows derivation of Firm utility gas price and converts to Jan 2000$
Isaac	-- Displays NW utility gas cost in form to be read into ISAAC model.
SWEG	-- Southwest Electric Generation gas price, linked to MAIN wellhead price forecast.
GASSUM	-- Summary table for gas price forecasts, linked to the individual sector worksheets.
Jan2000$ WOP_NG	-- World Oil and Wellhead Natural Gas price assumptions converted to January 2000 dollars.
OILMOD	-- Estimates retail oil prices for all sectors, linked to MAIN world oil price forecasts.
OilSum	-- Summary of retail oil price forecasts for residual and distillate in both midyear 2000 $ and Jan 2000$.
COALMOD	-- Forecasts industrial coal prices based on exogenous growth rate read from MAIN.

FUELS	-- Puts the fuel price forecasts in the format needed for input to demand forecasting models, converts to 1980 $
Export	-- File to be exported for demand model inputs.

Appendix B - Derivation of Natural Gas Prices by Market Points and States

Table B-1 shows the assumed relationships between wellhead price forecasts and various pricing points in the West. These price differential estimates are used to derive natural gas price inputs to the Aurora electricity pricing model.

Table B-1

Medium

	Basis Differential	Delivery Cost	2005 Price
Wellhead			$3.00
↓	$0.12		
Henry Hub			$3.12
→ Station 2	($0.35)		$2.77
→ → Sumas		$0.26	$3.03
→ → West-side PNW		$0.63	$3.40
→ AECO	($0.45)		$2.67
→ → East-side PNW		$0.36	$3.03
→ → Northern CA		$0.80	$3.47
→ San Juan	($0.26)		$2.86
→ → CO		$0.36	$3.22
→ Rockies	($0.40)		$2.72
→ → UT		$0.35	$3.07
→ → WY		$0.40	$3.12
→ → MT		$0.33	$3.05
→ → ID		$0.35	$3.07
→ Permian	($0.17)		$2.95
→ → CA Border		$0.33	$3.28
→ → → Southern CA		$0.05	$3.33
→ → AZ		$0.32	$3.27
→ → NM		$0.24	$3.19
→ → NV		$0.33	$3.28

Table B-1 shows prices for the medium case forecast. The only component of the basis differential column in the table that changes with forecast scenarios is the basis differential between Henry Hub and AECO and Station 2. The assumed Henry Hub to AECO differentials are shown below. The AECO basis differential is assumed, on average, to be $ .10 more negative than the Station 2 differential. In more detailed work we assume that the Station 2 price will be $ .20 higher than

AECO in winter, and about equal in summer. Some of the components of the northwest delivery costs also vary by forecast scenario and by season.

Basis Differential, Henry Hub to Sumas

Low	$ -.60
Medium Low	$ -.55
Medium	$ -.45
Medium High	$ -.30
High	$ -.20

Appendix C - Forecast Tables for U.S. Wellhead and Regional Retail Natural Gas Prices

Table C - Medium
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	4.29	3.52
2001	4.03	8.38	6.68	5.07	4.25
2002	2.70	6.95	5.95	3.55	2.53
2003	3.20	7.45	6.45	4.07	3.04
2004	3.10	7.35	6.35	3.96	2.91
2005	3.00	7.25	6.25	3.86	2.81
2006	3.00	7.25	6.25	3.86	2.85
2007	3.00	7.25	6.25	3.86	2.85
2008	3.00	7.25	6.25	3.85	2.85
2009	3.00	7.25	6.25	3.85	2.85
2010	3.00	7.25	6.25	3.85	2.85
2011	3.03	7.28	6.28	3.88	2.88
2012	3.06	7.31	6.31	3.91	2.91
2013	3.09	7.34	6.34	3.94	2.94
2014	3.12	7.37	6.37	3.97	2.98
2015	3.15	7.40	6.40	4.00	3.01
2016	3.16	7.41	6.41	4.01	3.02
2017	3.17	7.42	6.42	4.02	3.03
2018	3.18	7.43	6.43	4.03	3.04
2019	3.19	7.44	6.44	4.04	3.05
2020	3.20	7.45	6.45	4.05	3.06
2021	3.22	7.47	6.47	4.06	3.08
2022	3.24	7.49	6.49	4.08	3.11
2023	3.26	7.51	6.51	4.10	3.13
2024	3.28	7.53	6.53	4.12	3.15
2025	3.30	7.55	6.55	4.14	3.17

Table C - Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	4.29	3.52
2001	4.03	8.38	6.68	5.07	4.25
2002	2.35	6.60	5.60	3.08	2.01
2003	2.80	7.05	6.05	3.55	2.47
2004	2.70	6.95	5.95	3.44	2.35
2005	2.50	6.75	5.75	3.23	2.14
2006	2.46	6.71	5.71	3.19	2.14
2007	2.42	6.67	5.67	3.15	2.10
2008	2.38	6.63	5.63	3.10	2.06
2009	2.34	6.59	5.59	3.06	2.02
2010	2.30	6.55	5.55	3.02	1.98
2011	2.32	6.57	5.57	3.04	2.00
2012	2.34	6.59	5.59	3.06	2.02
2013	2.36	6.61	5.61	3.08	2.04
2014	2.38	6.63	5.63	3.10	2.06
2015	2.40	6.65	5.65	3.12	2.08
2016	2.42	6.67	5.67	3.14	2.10
2017	2.44	6.69	5.69	3.16	2.12
2018	2.46	6.71	5.71	3.17	2.14
2019	2.48	6.73	5.73	3.19	2.16
2020	2.50	6.75	5.75	3.21	2.18
2021	2.52	6.77	5.77	3.23	2.20
2022	2.54	6.79	5.79	3.25	2.22
2023	2.56	6.81	5.81	3.27	2.24
2024	2.58	6.83	5.83	3.29	2.26
2025	2.60	6.85	5.85	3.31	2.28

Table C - Medium-Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	4.29	3.52
2001	4.03	8.38	6.68	5.07	4.25
2002	2.45	6.70	5.70	3.22	2.17
2003	3.00	7.25	6.25	3.79	2.73
2004	2.90	7.15	6.15	3.68	2.60
2005	2.80	7.05	6.05	3.58	2.50
2006	2.76	7.01	6.01	3.54	2.50
2007	2.72	6.97	5.97	3.49	2.46
2008	2.68	6.93	5.93	3.45	2.42
2009	2.64	6.89	5.89	3.41	2.38
2010	2.60	6.85	5.85	3.37	2.34
2011	2.62	6.87	5.87	3.39	2.36
2012	2.64	6.89	5.89	3.40	2.38
2013	2.66	6.91	5.91	3.42	2.40
2014	2.68	6.93	5.93	3.44	2.42
2015	2.70	6.95	5.95	3.46	2.44
2016	2.74	6.99	5.99	3.50	2.48
2017	2.78	7.03	6.03	3.54	2.52
2018	2.82	7.07	6.07	3.58	2.56
2019	2.86	7.11	6.11	3.62	2.61
2020	2.90	7.15	6.15	3.66	2.65
2021	2.92	7.17	6.17	3.68	2.67
2022	2.94	7.19	6.19	3.70	2.69
2023	2.96	7.21	6.21	3.72	2.71
2024	2.98	7.23	6.23	3.74	2.73
2025	3.00	7.25	6.25	3.76	2.75

Table C - Medium-High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	4.29	3.52
2001	4.03	8.38	6.68	5.07	4.25
2002	2.80	7.05	6.05	3.77	2.78
2003	3.35	7.60	6.60	4.33	3.35
2004	3.25	7.50	6.50	4.23	3.22
2005	3.15	7.40	6.40	4.12	3.12
2006	3.16	7.41	6.41	4.13	3.17
2007	3.17	7.42	6.42	4.14	3.18
2008	3.18	7.43	6.43	4.15	3.19
2009	3.19	7.44	6.44	4.16	3.20
2010	3.20	7.45	6.45	4.17	3.21
2011	3.23	7.48	6.48	4.20	3.24
2012	3.26	7.51	6.51	4.23	3.27
2013	3.29	7.54	6.54	4.26	3.31
2014	3.32	7.57	6.57	4.29	3.34
2015	3.35	7.60	6.60	4.32	3.37
2016	3.38	7.63	6.63	4.34	3.40
2017	3.41	7.66	6.66	4.37	3.43
2018	3.44	7.69	6.69	4.40	3.47
2019	3.47	7.72	6.72	4.43	3.50
2020	3.50	7.75	6.75	4.46	3.53
2021	3.52	7.77	6.77	4.48	3.55
2022	3.54	7.79	6.79	4.50	3.57
2023	3.56	7.81	6.81	4.52	3.59
2024	3.58	7.83	6.83	4.54	3.62
2025	3.60	7.85	6.85	4.56	3.64

Table C - High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	4.29	3.52
2001	4.03	8.38	6.68	5.07	4.25
2002	2.90	7.15	6.15	3.94	2.99
2003	3.50	7.75	6.75	4.56	3.60
2004	3.30	7.55	6.55	4.35	3.37
2005	3.24	7.49	6.49	4.29	3.31
2006	3.27	7.52	6.52	4.32	3.38
2007	3.30	7.55	6.55	4.35	3.42
2008	3.34	7.59	6.59	4.38	3.45
2009	3.37	7.62	6.62	4.41	3.49
2010	3.40	7.65	6.65	4.45	3.52
2011	3.44	7.69	6.69	4.49	3.56
2012	3.48	7.73	6.73	4.53	3.60
2013	3.52	7.77	6.77	4.57	3.65
2014	3.56	7.81	6.81	4.61	3.69
2015	3.60	7.85	6.85	4.65	3.73
2016	3.64	7.89	6.89	4.69	3.77
2017	3.68	7.93	6.93	4.73	3.82
2018	3.72	7.97	6.97	4.77	3.86
2019	3.76	8.01	7.01	4.81	3.90
2020	3.80	8.05	7.05	4.85	3.95
2021	3.84	8.09	7.09	4.89	3.99
2022	3.88	8.13	7.13	4.93	4.03
2023	3.92	8.17	7.17	4.97	4.07
2024	3.96	8.21	7.21	5.01	4.11
2025	4.00	8.25	7.25	5.05	4.16

Appendix D - Forecast Tables for U.S. Wellhead and Regional Market Prices

Table D - Medium
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Case Year	U.S. Wellhead Price	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.70	2.37	2.47	3.09	2.75
2003	3.20	2.87	2.97	3.61	3.26
2004	3.10	2.77	2.87	3.56	3.16
2005	3.00	2.67	2.77	3.45	3.06
2006	3.00	2.67	2.77	3.55	3.15
2007	3.00	2.67	2.77	3.56	3.15
2008	3.00	2.67	2.77	3.56	3.15
2009	3.00	2.67	2.77	3.57	3.16
2010	3.00	2.67	2.77	3.57	3.16
2011	3.03	2.70	2.80	3.60	3.19
2012	3.06	2.73	2.83	3.64	3.23
2013	3.09	2.76	2.86	3.68	3.26
2014	3.12	2.79	2.89	3.71	3.29
2015	3.15	2.82	2.92	3.75	3.33
2016	3.16	2.83	2.93	3.76	3.34
2017	3.17	2.84	2.94	3.78	3.35
2018	3.18	2.85	2.95	3.79	3.37
2019	3.19	2.86	2.96	3.81	3.38
2020	3.20	2.87	2.97	3.82	3.39
2021	3.22	2.89	2.99	3.85	3.42
2022	3.24	2.91	3.01	3.87	3.44
2023	3.26	2.93	3.03	3.90	3.47
2024	3.28	2.95	3.05	3.93	3.49
2025	3.30	2.97	3.07	3.95	3.51

Table D - Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Year	Low Case U.S. Wellhead Price	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.35	1.87	1.97	2.57	2.24
2003	2.80	2.32	2.42	3.04	2.70
2004	2.70	2.22	2.32	2.98	2.60
2005	2.50	2.02	2.12	2.77	2.39
2006	2.46	1.98	2.08	2.83	2.44
2007	2.42	1.94	2.04	2.79	2.40
2008	2.38	1.90	2.00	2.75	2.36
2009	2.34	1.86	1.96	2.71	2.32
2010	2.30	1.82	1.92	2.67	2.28
2011	2.32	1.84	1.94	2.69	2.30
2012	2.34	1.86	1.96	2.71	2.32
2013	2.36	1.88	1.98	2.73	2.34
2014	2.38	1.90	2.00	2.75	2.36
2015	2.40	1.92	2.02	2.77	2.38
2016	2.42	1.94	2.04	2.79	2.40
2017	2.44	1.96	2.06	2.81	2.42
2018	2.46	1.98	2.08	2.83	2.44
2019	2.48	2.00	2.10	2.85	2.46
2020	2.50	2.02	2.12	2.87	2.48
2021	2.52	2.04	2.14	2.89	2.50
2022	2.54	2.06	2.16	2.92	2.52
2023	2.56	2.08	2.18	2.94	2.54
2024	2.58	2.10	2.20	2.96	2.56
2025	2.60	2.12	2.22	2.98	2.58

Table D - Medium-Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case Year	U.S. Wellhead Price	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.45	2.02	2.12	2.72	2.39
2003	3.00	2.57	2.67	3.30	2.96
2004	2.90	2.47	2.57	3.24	2.85
2005	2.80	2.37	2.47	3.14	2.75
2006	2.76	2.33	2.43	3.20	2.80
2007	2.72	2.29	2.39	3.16	2.76
2008	2.68	2.25	2.35	3.12	2.72
2009	2.64	2.21	2.31	3.08	2.68
2010	2.60	2.17	2.27	3.04	2.64
2011	2.62	2.19	2.29	3.06	2.66
2012	2.64	2.21	2.31	3.08	2.68
2013	2.66	2.23	2.33	3.11	2.71
2014	2.68	2.25	2.35	3.13	2.73
2015	2.70	2.27	2.37	3.15	2.75
2016	2.74	2.31	2.41	3.19	2.79
2017	2.78	2.35	2.45	3.24	2.83
2018	2.82	2.39	2.49	3.28	2.87
2019	2.86	2.43	2.53	3.32	2.92
2020	2.90	2.47	2.57	3.37	2.96
2021	2.92	2.49	2.59	3.39	2.98
2022	2.94	2.51	2.61	3.41	3.00
2023	2.96	2.53	2.63	3.44	3.03
2024	2.98	2.55	2.65	3.46	3.05
2025	3.00	2.57	2.67	3.48	3.07

Table D - Medium-High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case

Year	U.S. Wellhead Price	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.80	2.62	2.72	3.35	3.01
2003	3.35	3.17	3.27	3.92	3.57
2004	3.25	3.07	3.17	3.87	3.47
2005	3.15	2.97	3.07	3.77	3.37
2006	3.16	2.98	3.08	3.88	3.47
2007	3.17	2.99	3.09	3.89	3.48
2008	3.18	3.00	3.10	3.91	3.49
2009	3.19	3.01	3.11	3.93	3.51
2010	3.20	3.02	3.12	3.94	3.52
2011	3.23	3.05	3.15	3.98	3.56
2012	3.26	3.08	3.18	4.02	3.59
2013	3.29	3.11	3.21	4.05	3.63
2014	3.32	3.14	3.24	4.09	3.66
2015	3.35	3.17	3.27	4.13	3.70
2016	3.38	3.20	3.30	4.17	3.73
2017	3.41	3.23	3.33	4.21	3.77
2018	3.44	3.26	3.36	4.24	3.80
2019	3.47	3.29	3.39	4.28	3.84
2020	3.50	3.32	3.42	4.32	3.87
2021	3.52	3.34	3.44	4.35	3.90
2022	3.54	3.36	3.46	4.38	3.92
2023	3.56	3.38	3.48	4.40	3.95
2024	3.58	3.40	3.50	4.43	3.98
2025	3.60	3.42	3.52	4.46	4.00

Table D - High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Year	High Case U.S. Wellhead Price	AECO Price	Station 2 Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	3.47	4.13	3.75
2001	4.03	4.05	4.15	4.85	4.48
2002	2.90	2.82	2.92	3.56	3.21
2003	3.50	3.42	3.52	4.19	3.83
2004	3.30	3.22	3.32	4.03	3.62
2005	3.24	3.16	3.26	3.96	3.56
2006	3.27	3.19	3.29	4.10	3.68
2007	3.30	3.22	3.32	4.14	3.72
2008	3.34	3.26	3.36	4.18	3.76
2009	3.37	3.29	3.39	4.22	3.80
2010	3.40	3.32	3.42	4.26	3.84
2011	3.44	3.36	3.46	4.31	3.88
2012	3.48	3.40	3.50	4.36	3.93
2013	3.52	3.44	3.54	4.41	3.97
2014	3.56	3.48	3.58	4.46	4.02
2015	3.60	3.52	3.62	4.51	4.07
2016	3.64	3.56	3.66	4.56	4.12
2017	3.68	3.60	3.70	4.61	4.16
2018	3.72	3.64	3.74	4.66	4.21
2019	3.76	3.68	3.78	4.72	4.26
2020	3.80	3.72	3.82	4.77	4.30
2021	3.84	3.76	3.86	4.82	4.35
2022	3.88	3.80	3.90	4.87	4.40
2023	3.92	3.84	3.94	4.92	4.45
2024	3.96	3.88	3.98	4.97	4.49
2025	4.00	3.92	4.02	5.02	4.54

Appendix E - Forecast Tables for World Oil and Regional Retail Oil Prices

Table E - Medium
Retail Oil Price Forecast

Year	Medium Case World Oil Price (2000$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (2000$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (2000$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (2000$/MMBtu)	Utility Residual Oil Price (2000$/MMBtu)	Utility Distillate Oil Price
2000	27.69	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2002	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2003	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2004	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2005	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2006	22.10	3.26	6.17	6.00	3.31	5.75	5.64	8.15	3.26	5.63
2007	22.20	3.28	6.19	6.02	3.33	5.77	5.65	8.17	3.28	5.65
2008	22.30	3.29	6.21	6.04	3.34	5.79	5.67	8.19	3.29	5.67
2009	22.40	3.31	6.23	6.06	3.36	5.81	5.69	8.21	3.31	5.69
2010	22.50	3.32	6.25	6.08	3.37	5.83	5.71	8.23	3.32	5.71
2011	22.60	3.34	6.27	6.10	3.39	5.85	5.73	8.25	3.34	5.73
2012	22.70	3.35	6.29	6.12	3.40	5.87	5.75	8.27	3.35	5.75
2013	22.80	3.37	6.31	6.13	3.42	5.89	5.77	8.29	3.37	5.77
2014	22.90	3.38	6.33	6.15	3.43	5.91	5.79	8.31	3.38	5.79
2015	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2016	23.10	3.41	6.36	6.19	3.46	5.94	5.83	8.34	3.41	5.82
2017	23.20	3.43	6.38	6.21	3.48	5.96	5.85	8.36	3.43	5.84
2018	23.30	3.44	6.40	6.23	3.49	5.98	5.86	8.38	3.44	5.86
2019	23.40	3.46	6.42	6.25	3.51	6.00	5.88	8.40	3.46	5.88
2020	23.50	3.47	6.44	6.27	3.52	6.02	5.90	8.42	3.47	5.90
2021	23.60	3.48	6.46	6.29	3.53	6.04	5.92	8.44	3.48	5.92
2022	23.70	3.50	6.48	6.30	3.55	6.06	5.94	8.46	3.50	5.94
2023	23.80	3.51	6.50	6.32	3.56	6.08	5.96	8.48	3.51	5.96
2024	23.90	3.53	6.52	6.34	3.58	6.10	5.98	8.50	3.53	5.98
2025	24.00	3.54	6.54	6.36	3.59	6.12	6.00	8.52	3.54	6.00

Table E - Low
Retail Oil Price Forecast

Year	Low Case World Oil Price (00$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (00$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (00$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (00$/MMBtu)	Utility Residual Oil Price (00$/MMBtu)	Utility Distillate Oil Price
2000	27.69	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.00	3.10	5.96	5.79	3.15	5.54	5.43	7.94	3.10	5.42
2002	21.00	3.10	5.96	5.79	3.15	5.54	5.43	7.94	3.10	5.42
2003	20.00	2.95	5.77	5.60	3.00	5.35	5.24	7.75	2.95	5.23
2004	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2005	16.00	2.36	5.00	4.84	2.41	4.58	4.48	6.98	2.36	4.46
2006	16.14	2.38	5.03	4.87	2.43	4.61	4.50	7.01	2.38	4.49
2007	16.28	2.40	5.05	4.90	2.45	4.63	4.53	7.03	2.40	4.51
2008	16.42	2.42	5.08	4.92	2.47	4.66	4.56	7.06	2.42	4.54
2009	16.56	2.44	5.11	4.95	2.49	4.69	4.58	7.09	2.44	4.57
2010	16.70	2.47	5.13	4.98	2.52	4.71	4.61	7.11	2.47	4.59
2011	16.84	2.49	5.16	5.00	2.54	4.74	4.64	7.14	2.49	4.62
2012	16.98	2.51	5.19	5.03	2.56	4.77	4.66	7.17	2.51	4.65
2013	17.12	2.53	5.21	5.06	2.58	4.79	4.69	7.19	2.53	4.67
2014	17.26	2.55	5.24	5.08	2.60	4.82	4.72	7.22	2.55	4.70
2015	17.40	2.57	5.27	5.11	2.62	4.85	4.74	7.25	2.57	4.73
2016	17.56	2.59	5.30	5.14	2.64	4.88	4.77	7.28	2.59	4.76
2017	17.72	2.62	5.33	5.17	2.67	4.91	4.80	7.31	2.62	4.79
2018	17.88	2.64	5.36	5.20	2.69	4.94	4.83	7.34	2.64	4.82
2019	18.04	2.66	5.39	5.23	2.71	4.97	4.86	7.37	2.66	4.85
2020	18.20	2.69	5.42	5.26	2.74	5.00	4.89	7.40	2.69	4.88
2021	18.36	2.71	5.45	5.29	2.76	5.03	4.92	7.43	2.71	4.91
2022	18.52	2.73	5.48	5.32	2.78	5.06	4.95	7.46	2.73	4.94
2023	18.68	2.76	5.51	5.35	2.81	5.09	4.99	7.49	2.76	4.97
2024	18.84	2.78	5.55	5.38	2.83	5.13	5.02	7.53	2.78	5.01
2025	19.00	2.81	5.58	5.41	2.86	5.16	5.05	7.56	2.81	5.04

Table E - Medium-Low
Retail Oil Price Forecast

Year	Medium Low Case World Oil Price (00$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (00$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (00$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (00$/MMBtu)	Utility Residual Oil Price (00$/MMBtu)	Utility Distillate Oil Price
2000	27.69	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2002	22.00	3.25	6.15	5.98	3.30	5.73	5.62	8.13	3.25	5.61
2003	21.00	3.10	5.96	5.79	3.15	5.54	5.43	7.94	3.10	5.42
2004	21.00	3.10	5.96	5.79	3.15	5.54	5.43	7.94	3.10	5.42
2005	19.00	2.81	5.58	5.41	2.86	5.16	5.05	7.56	2.81	5.04
2006	19.10	2.82	5.60	5.43	2.87	5.18	5.07	7.58	2.82	5.06
2007	19.20	2.83	5.61	5.45	2.88	5.19	5.08	7.59	2.83	5.07
2008	19.30	2.85	5.63	5.47	2.90	5.21	5.10	7.61	2.85	5.09
2009	19.40	2.86	5.65	5.49	2.91	5.23	5.12	7.63	2.86	5.11
2010	19.50	2.88	5.67	5.51	2.93	5.25	5.14	7.65	2.88	5.13
2011	19.60	2.89	5.69	5.53	2.94	5.27	5.16	7.67	2.89	5.15
2012	19.70	2.91	5.71	5.55	2.96	5.29	5.18	7.69	2.91	5.17
2013	19.80	2.92	5.73	5.57	2.97	5.31	5.20	7.71	2.92	5.19
2014	19.90	2.94	5.75	5.58	2.99	5.33	5.22	7.73	2.94	5.21
2015	20.00	2.95	5.77	5.60	3.00	5.35	5.24	7.75	2.95	5.23
2016	20.10	2.97	5.79	5.62	3.02	5.37	5.26	7.77	2.97	5.25
2017	20.20	2.98	5.81	5.64	3.03	5.39	5.27	7.79	2.98	5.27
2018	20.30	3.00	5.83	5.66	3.05	5.41	5.29	7.81	3.00	5.29
2019	20.40	3.01	5.85	5.68	3.06	5.43	5.31	7.83	3.01	5.31
2020	20.50	3.03	5.87	5.70	3.08	5.45	5.33	7.85	3.03	5.33
2021	20.60	3.04	5.88	5.72	3.09	5.46	5.35	7.86	3.04	5.34
2022	20.70	3.06	5.90	5.74	3.11	5.48	5.37	7.88	3.06	5.36
2023	20.80	3.07	5.92	5.75	3.12	5.50	5.39	7.90	3.07	5.38
2024	20.90	3.09	5.94	5.77	3.14	5.52	5.41	7.92	3.09	5.40
2025	21.00	3.10	5.96	5.79	3.15	5.54	5.43	7.94	3.10	5.42

Table E - Medium-High
Retail Oil Price Forecast

Year	Medium High Case World Oil Price (00$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (00$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (00$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (00$/MMBtu)	Utility Residual Oil Price (00$/MMBtu)	Utility Distillate Oil Price
2000	27.69	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	24.00	3.54	6.54	6.36	3.59	6.12	6.00	8.52	3.54	6.00
2002	24.00	3.54	6.54	6.36	3.59	6.12	6.00	8.52	3.54	6.00
2003	24.00	3.54	6.54	6.36	3.59	6.12	6.00	8.52	3.54	6.00
2004	24.00	3.54	6.54	6.36	3.59	6.12	6.00	8.52	3.54	6.00
2005	25.00	3.69	6.73	6.55	3.74	6.31	6.19	8.71	3.69	6.19
2006	25.10	3.71	6.75	6.57	3.76	6.33	6.21	8.73	3.71	6.21
2007	25.20	3.72	6.77	6.59	3.77	6.35	6.23	8.75	3.72	6.23
2008	25.30	3.74	6.79	6.61	3.79	6.37	6.24	8.77	3.74	6.25
2009	25.40	3.75	6.81	6.63	3.80	6.39	6.26	8.79	3.75	6.27
2010	25.50	3.77	6.83	6.65	3.82	6.41	6.28	8.81	3.77	6.29
2011	25.60	3.78	6.85	6.67	3.83	6.43	6.30	8.83	3.78	6.31
2012	25.70	3.79	6.86	6.68	3.84	6.44	6.32	8.84	3.79	6.32
2013	25.80	3.81	6.88	6.70	3.86	6.46	6.34	8.86	3.81	6.34
2014	25.90	3.82	6.90	6.72	3.87	6.48	6.36	8.88	3.82	6.36
2015	26.00	3.84	6.92	6.74	3.89	6.50	6.38	8.90	3.84	6.38
2016	26.10	3.85	6.94	6.76	3.90	6.52	6.40	8.92	3.85	6.40
2017	26.20	3.87	6.96	6.78	3.92	6.54	6.42	8.94	3.87	6.42
2018	26.30	3.88	6.98	6.80	3.93	6.56	6.43	8.96	3.88	6.44
2019	26.40	3.90	7.00	6.82	3.95	6.58	6.45	8.98	3.90	6.46
2020	26.50	3.91	7.02	6.84	3.96	6.60	6.47	9.00	3.91	6.48
2021	26.60	3.93	7.04	6.86	3.98	6.62	6.49	9.02	3.93	6.50
2022	26.70	3.94	7.06	6.87	3.99	6.64	6.51	9.04	3.94	6.52
2023	26.80	3.96	7.08	6.89	4.01	6.66	6.53	9.06	3.96	6.54
2024	26.90	3.97	7.10	6.91	4.02	6.68	6.55	9.08	3.97	6.56
2025	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58

Table E - High
Retail Oil Price Forecast

Year	High Case World Oil Price (00$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (00$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (00$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (00$/MMBtu)	Utility Residual Oil Price (00$/MMBtu)	Utility Distillate Oil Price
2000	27.69	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	25.00	3.69	6.73	6.55	3.74	6.31	6.19	8.71	3.69	6.19
2002	26.00	3.84	6.92	6.74	3.89	6.50	6.38	8.90	3.84	6.38
2003	29.00	4.28	7.50	7.31	4.33	7.08	6.95	9.48	4.28	6.96
2004	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2005	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2006	30.10	4.44	7.71	7.52	4.49	7.29	7.16	9.69	4.44	7.17
2007	30.20	4.46	7.73	7.54	4.51	7.31	7.18	9.71	4.46	7.19
2008	30.30	4.47	7.75	7.56	4.52	7.33	7.20	9.73	4.47	7.21
2009	30.40	4.49	7.77	7.58	4.54	7.35	7.21	9.75	4.49	7.23
2010	30.50	4.50	7.79	7.59	4.55	7.37	7.23	9.77	4.50	7.25
2011	30.60	4.52	7.81	7.61	4.57	7.39	7.25	9.79	4.52	7.27
2012	30.70	4.53	7.83	7.63	4.58	7.41	7.27	9.81	4.53	7.29
2013	30.80	4.55	7.85	7.65	4.60	7.43	7.29	9.83	4.55	7.31
2014	30.90	4.56	7.86	7.67	4.61	7.44	7.31	9.84	4.56	7.32
2015	31.00	4.58	7.88	7.69	4.63	7.46	7.33	9.86	4.58	7.34
2016	31.10	4.59	7.90	7.71	4.64	7.48	7.35	9.88	4.59	7.36
2017	31.20	4.61	7.92	7.73	4.66	7.50	7.37	9.90	4.61	7.38
2018	31.30	4.62	7.94	7.75	4.67	7.52	7.39	9.92	4.62	7.40
2019	31.40	4.64	7.96	7.77	4.69	7.54	7.40	9.94	4.64	7.42
2020	31.50	4.65	7.98	7.78	4.70	7.56	7.42	9.96	4.65	7.44
2021	31.60	4.67	8.00	7.80	4.72	7.58	7.44	9.98	4.67	7.46
2022	31.70	4.68	8.02	7.82	4.73	7.60	7.46	10.00	4.68	7.48
2023	31.80	4.70	8.04	7.84	4.75	7.62	7.48	10.02	4.70	7.50
2024	31.90	4.71	8.06	7.86	4.76	7.64	7.50	10.04	4.71	7.52
2025	32.00	4.73	8.08	7.88	4.78	7.66	7.52	10.06	4.73	7.54

Appendix F - Forecast Tables for Western Minemouth and Regional Delivered Coal Prices

Table F - Medium
Coal Price Forecasts
(2000$ Per MMBtu)

Medium Case			Selected State Electricity Generation Coal Prices					
Year	Western Minmouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.11	1.65	1.09	0.00	0.71	1.39
2001	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.16
2002	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.15
2003	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.15
2004	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.14
2005	0.49	2.09	1.09	1.54	1.03	0.94	0.69	1.14
2006	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.14
2007	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.13
2008	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.13
2009	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.12
2010	0.47	2.07	1.07	1.52	1.01	0.92	0.67	1.12
2011	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.12
2012	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.11
2013	0.46	2.06	1.06	1.50	1.00	0.91	0.66	1.11
2014	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.10
2015	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.10
2016	0.45	2.05	1.05	1.49	0.98	0.90	0.65	1.10
2017	0.45	2.05	1.05	1.49	0.98	0.90	0.65	1.09
2018	0.44	2.04	1.04	1.49	0.98	0.89	0.64	1.09
2019	0.44	2.04	1.04	1.48	0.97	0.89	0.64	1.09
2020	0.44	2.04	1.04	1.48	0.97	0.89	0.64	1.08
2021	0.43	2.03	1.03	1.48	0.97	0.88	0.63	1.08
2022	0.43	2.03	1.03	1.47	0.96	0.88	0.63	1.08
2023	0.43	2.03	1.03	1.47	0.96	0.88	0.63	1.07
2024	0.42	2.02	1.02	1.47	0.96	0.87	0.62	1.07
2025	0.42	2.02	1.02	1.46	0.95	0.87	0.62	1.07

Table F - Low
Coal Price Forecasts
(2000$ Per MMBtu)

	Low Case		Selected State Electricity Generation Coal Prices					
Year	Western Minmouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.11	1.65	1.09	0.00	0.71	1.39
2001	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.15
2002	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.14
2003	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.14
2004	0.48	2.08	1.08	1.53	1.02	0.93	0.68	1.13
2005	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.12
2006	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.11
2007	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.11
2008	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.10
2009	0.45	2.05	1.05	1.49	0.98	0.90	0.65	1.09
2010	0.44	2.04	1.04	1.48	0.97	0.89	0.64	1.09
2011	0.43	2.03	1.03	1.48	0.97	0.88	0.63	1.08
2012	0.43	2.03	1.03	1.47	0.96	0.88	0.63	1.07
2013	0.42	2.02	1.02	1.46	0.95	0.87	0.62	1.07
2014	0.42	2.02	1.02	1.46	0.95	0.87	0.62	1.06
2015	0.41	2.01	1.01	1.45	0.94	0.86	0.61	1.06
2016	0.40	2.00	1.00	1.45	0.94	0.85	0.60	1.05
2017	0.40	2.00	1.00	1.44	0.93	0.85	0.60	1.04
2018	0.39	1.99	0.99	1.43	0.92	0.84	0.59	1.04
2019	0.39	1.99	0.99	1.43	0.92	0.84	0.59	1.03
2020	0.38	1.98	0.98	1.42	0.91	0.83	0.58	1.03
2021	0.37	1.97	0.97	1.42	0.91	0.82	0.57	1.02
2022	0.37	1.97	0.97	1.41	0.90	0.82	0.57	1.01
2023	0.36	1.96	0.96	1.40	0.90	0.81	0.56	1.01
2024	0.36	1.96	0.96	1.40	0.89	0.81	0.56	1.00
2025	0.35	1.95	0.95	1.39	0.88	0.80	0.55	1.00

**Table F - Medium-Low
Coal Price Forecasts
(2000$ Per MMBtu)**

Medium Low Case			Selected State Electricity Generation Coal Prices					
Year	Western Minmouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.11	1.65	1.09	0.00	0.71	1.39
2001	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.15
2002	0.50	2.10	1.10	1.54	1.04	0.95	0.70	1.15
2003	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.14
2004	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.14
2005	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.13
2006	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.13
2007	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.12
2008	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.12
2009	0.46	2.06	1.06	1.51	1.00	0.91	0.66	1.11
2010	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.11
2011	0.45	2.05	1.05	1.50	0.99	0.90	0.65	1.10
2012	0.45	2.05	1.05	1.49	0.98	0.90	0.65	1.10
2013	0.44	2.04	1.04	1.49	0.98	0.89	0.64	1.09
2014	0.44	2.04	1.04	1.48	0.97	0.89	0.64	1.09
2015	0.44	2.04	1.04	1.48	0.97	0.89	0.64	1.08
2016	0.43	2.03	1.03	1.47	0.96	0.88	0.63	1.08
2017	0.43	2.03	1.03	1.47	0.96	0.88	0.63	1.07
2018	0.42	2.02	1.02	1.46	0.95	0.87	0.62	1.07
2019	0.42	2.02	1.02	1.46	0.95	0.87	0.62	1.06
2020	0.41	2.01	1.01	1.45	0.94	0.86	0.61	1.06
2021	0.41	2.01	1.01	1.45	0.94	0.86	0.61	1.05
2022	0.40	2.00	1.00	1.44	0.94	0.85	0.60	1.05
2023	0.40	2.00	1.00	1.44	0.93	0.85	0.60	1.04
2024	0.39	1.99	0.99	1.44	0.93	0.84	0.59	1.04
2025	0.39	1.99	0.99	1.43	0.92	0.84	0.59	1.04

Table F - Medium-High
Coal Price Forecasts
(2000$ Per MMBtu)

Medium High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minmouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.11	1.65	1.09	0.00	0.71	1.39
2001	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.16
2002	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.15
2003	0.51	2.11	1.11	1.55	1.04	0.96	0.71	1.15
2004	0.50	2.10	1.10	1.55	1.04	0.95	0.70	1.15
2005	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.15
2006	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.14
2007	0.50	2.10	1.10	1.54	1.03	0.95	0.70	1.14
2008	0.49	2.09	1.09	1.54	1.03	0.94	0.69	1.14
2009	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.14
2010	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.13
2011	0.49	2.09	1.09	1.53	1.02	0.94	0.69	1.13
2012	0.48	2.08	1.08	1.53	1.02	0.93	0.68	1.13
2013	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.13
2014	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.12
2015	0.48	2.08	1.08	1.52	1.01	0.93	0.68	1.12
2016	0.47	2.07	1.07	1.52	1.01	0.92	0.67	1.12
2017	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.12
2018	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.12
2019	0.47	2.07	1.07	1.51	1.00	0.92	0.67	1.11
2020	0.46	2.06	1.06	1.51	1.00	0.91	0.66	1.11
2021	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.11
2022	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.11
2023	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.10
2024	0.46	2.06	1.06	1.50	0.99	0.91	0.66	1.10
2025	0.45	2.05	1.05	1.50	0.99	0.90	0.65	1.10

Table F - High
Coal Price Forecasts
(2000$ Per MMBtu)

High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minmouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.11	1.65	1.09	0.00	0.71	1.39
2001	0.51	2.11	1.11	1.56	1.05	0.96	0.71	1.16
2002	0.51	2.11	1.11	1.56	1.05	0.96	0.71	1.16
2003	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2004	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2005	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2006	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2007	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2008	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2009	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2010	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.16
2011	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2012	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2013	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2014	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2015	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2016	0.52	2.12	1.12	1.56	1.05	0.97	0.72	1.17
2017	0.52	2.12	1.12	1.56	1.06	0.97	0.72	1.17
2018	0.52	2.12	1.12	1.57	1.06	0.97	0.72	1.17
2019	0.52	2.12	1.12	1.57	1.06	0.97	0.72	1.17
2020	0.52	2.12	1.12	1.57	1.06	0.97	0.72	1.17
2021	0.52	2.12	1.12	1.57	1.06	0.97	0.72	1.17
2022	0.52	2.12	1.12	1.57	1.06	0.97	0.72	1.17
2023	0.53	2.13	1.13	1.57	1.06	0.98	0.73	1.17
2024	0.53	2.13	1.13	1.57	1.06	0.98	0.73	1.17
2025	0.53	2.13	1.13	1.57	1.06	0.98	0.73	1.17

q:\rb\ww\power\power plan\natural gas-2.doc